PUBLIC SERVICE COMMISSION OF WISCONSIN

STRATEGIC ENERGY ASSESSMENT

ENERGY 2014

ENSURING THE AVAILABILITY, RELIABILITY AND SUSTAINABILITY OF WISCONSIN'S ELECTRIC ENERGY SUPPLY

FINAL REPORT

610 NORTH WHITNEY WAY
MADISON, WISCONSIN

APRIL 2009
DOCKET 5-ES-104

To the Reader

This is the fifth biennial Strategic Energy Assessment (SEA) issued by the Public Service Commission of Wisconsin (Commission or PSC), an independent state regulatory agency, whose authority and responsibilities include regulatory oversight of electric service in Wisconsin. The SEA provides a picture of past and future electric energy needs and sources of supply. It brings to light issues that may need to be addressed to ensure the availability, reliability, and sustainability of Wisconsin's electric energy supply.

In the SEA dated February 2007, the Commission listed four general areas of concern that it would focus on as it moved forward with strategic initiatives. These were:

Environmentally Sustainable Energy Alternatives

The Commission's subsequent involvement in the Governor's Task Force on Global Warming (GWTF), which released its Final Report in July 2008, has helped focus the main issues and goals related to the important issues regarding the environment and sound energy policy. The Commission has been implementing many of the GWTF recommendations.

Accountability in the Regional Wholesale Market

The Commission's efforts and involvement with the Midwest Independent Transmission System Operator, Inc. (MISO), including emphasis on performance and accountability, continues on an ongoing basis.

Improved Planning Process

The inclusion of expanded sections in this final SEA regarding generation and transmission planning will facilitate added scrutiny needed regarding energy planning, especially for those issues related to the environment and the availability of sustainable energy alternatives.

Utility Workforce Planning

This issue has been followed by the Commission in recent rate proceedings and will continue to be monitored in order to maintain safe and reliable electric service statewide.

MOVING FORWARD

While the Commission is required to prepare this technical document for comments by parties involved in the electric industry, it also intends that the SEA be available to the general public having an interest in reliable, reasonably priced electric energy. To assist the general public, definitions of key terms used within the electric industry are included in this report.

The Commission is required to hold a public hearing before issuing a final SEA. A copy of the notice providing information on the hearing is included with this mailing, and is available for review on the Commission's website http://psc.wi.gov.

Written comments and comments presented at the public hearing have been used to prepare the final SEA. Questions regarding the final SEA or requests for additional copies should be directed to Project Coordinator Christine Swailes at (608) 266-8776. Questions from the media and the legislature may be directed to Director of Governmental and Public Affairs Timothy Le Monds at (608) 266-9600.

Public Service Commission of Wisconsin
Phone 608.266.5481 • Fax 608.266-3957 • TTY 608.267-1479
E-mail: pscrecs@psc.state.wi.us • Home Page: http://psc.wi.gov

Table of Contents

STRATEGIC ENERGY ASSESSMENT: ENERGY 2014

PERSPECTIVE FROM THE COMMISSION

Mandatory Constraints on Greenhouse Gas Emissions Appear to be Inevitable

Mandatory constraints on greenhouse gas (GHG) emissions are coming. Developments at the state, regional, and federal level all trend in that direction.

Here in Wisconsin, the Governor's Task Force on Global Warming (GWTF) recently recommended aggressive GHG reduction targets (22 percent below 2005 levels by 2022, and 75 percent below 2005 levels by 2050), but acknowledged that, absent mandatory GHG emission constraints, the dozens of other policies recommended by the GWTF would enable Wisconsin to achieve only a fraction of its recommended reduction targets. A host of complementary climate change policies supported by the GWTF are expected to be considered by the Wisconsin Legislature this year.

In November 2007, Governor Doyle, along with the leaders of several other Midwestern states and one Canadian province, signed the Midwestern Greenhouse Gas Reduction Accord (Accord), pledging Wisconsin's participation in the development of a regional GHG cap and trade program. Representatives of both the Public Service Commission (Commission) and the Department of Natural Resources (DNR) have been engaged in the Accord process since then, and Accord participants are currently developing a draft model cap and trade rule for possible use in the region.

And at the federal level, President Obama and Congressional leaders have signaled their support for mandatory GHG emission reductions in the U.S. and their desire for a post-2012 international agreement on climate change.

Moreover, earlier this year, the U.S. Environmental Protection Agency (EPA) announced that it will reconsider whether carbon dioxide (CO_2) emissions should be a factor that EPA takes into account when it evaluates permitting for electric generating plants. That development follows an April 2007 U.S. Supreme Court ruling in *Massachusetts v. EPA* that CO_2 meets the definition of "air pollutant" under the federal Clean Air Act, and that EPA consequently has the legal authority to regulate emissions even without federal climate legislation. The Supreme Court further concluded that EPA can avoid regulating CO_2 "only if it determines that greenhouse gases do not contribute to climate change or if it provides some reasonable explanation as to why it cannot or will not exercise its discretion to determine whether they do."

Recent Commission actions have considered this apparent inevitability of mandatory constraints on GHG emissions. In the Oak Creek Pollution Controls docket, for example, the Commission recognized that "electric utilities will likely be operating in a carbon-constrained world in the near future, and that rate increases resulting from a cap and trade system may be a part of that future." The Commission's order in the Nelson Dewey 3 docket stated even more succinctly that "carbon constraints are imminent."

Electric Utilities will be Substantially Impacted by GHG Emissions Constraints

The implications of carbon regulation for the electric generation sector are huge. Electric generation is directly responsible for more than 30 percent of GHG emissions in Wisconsin and the nation as a whole. Every active GHG cap and trade program in the world and every proposal to date in the U.S. Congress has included electric generation within its regulatory scope. Because mandatory regulation of the electric generation sector appears to be inevitable, the Commission will consider likely future GHG emission constraints as one of many factors when it makes decisions about the economic regulation of energy utilities.

State Energy Policy

The Commission is guided in energy policy decisions by Wis. Stat. § 1.12, which reads as follows: "In meeting energy demands, the policy of the state is that, to the extent cost–effective and technically feasible, options be considered based on the following priorities, in the order listed: (a) Energy conservation and efficiency. (b) Noncombustible renewable energy resources. (c) Combustible renewable energy resources. (d) Nonrenewable combustible energy resources, in the order listed: 1. Natural gas. 2. Oil or coal with a sulphur content of less than 1 percent. 3. All other carbon–based fuels." The challenge of addressing global climate change will not change Wisconsin's energy priorities, but it is already leading to changes in what is considered "cost-effective and technically feasible."

Energy Conservation and Efficiency

Wisconsin lawmakers appropriately placed their highest priority on energy conservation and efficiency measures because these measures have the greatest potential to simultaneously and immediately reduce energy costs, human health impacts from air pollution, and global warming. The GWTF concurred with this approach, noting that conservation and efficiency are "the most effective, least-costly early action that can be taken to reduce GHG emissions."

The Commission works in partnership with electric providers and other private sector entities to implement Wisconsin's Focus on Energy program. Focus on Energy is a nationally recognized model for reducing energy demand through conservation and efficiency measures, and a three-time winner of the national Energy Star® Sustained Excellence Award. Last year the Commission opened docket 5-UI-115, Investigation into the Adoption and Achievement of Increased Conservation and Energy Efficiency Goals. This investigation stems from a recommendation of the GWTF to explore the potential for a significant expansion of the already successful Focus on Energy program.

The Commission is also pursuing two other energy conservation and efficiency policies recommended by the GWTF:

- Docket 5-UI-114, Investigation on the Commission's Own Motion Regarding Innovative Utility Ratemaking Approaches that Promote Conservation and Efficiency Programs by Removing Disincentives that May Exist Under Current Ratemaking Policies; and
- Docket 5-UI-116, Investigation to Develop and Analyze Alternative Electric and Natural Gas Rate Design and Load Management Options which have the Potential to Reduce Emissions of Greenhouse Gases.

Renewable Energy Resources

Renewable energy resources are Wisconsin's second highest priority for meeting energy demands, yet renewable resources currently provide only a small portion of Wisconsin's electricity (4.3 percent of capacity and 2.8 percent of actual generation in 2006). Historically, most renewable energy technologies have not been cost effective when compared to carbon-based fuel technologies and when the metric is production cost. The Renewable Portfolio Standard (RPS), the volatility of natural gas prices, and improved renewable technology have resulted in increasing use of renewable energy by Wisconsin utilities in the last few years. If and when mandatory GHG emission constraints are imposed, renewable energy resources will become increasingly cost effective.

The Commission has a central role in developing and implementing policies to encourage and support renewable energy installations. The Commission's approach makes use of both voluntary and mandatory policy measures. On the voluntary side, Wisconsin's successful Focus on Energy program includes a renewable energy component in addition to the previously mentioned conservation and efficiency programs. And on the mandatory side, the Commission is responsible for ensuring that electric providers comply with Wisconsin's RPS, as detailed in Wis. Stat. § 196.378. The combined effect of this standard on all electric providers will ensure that Wisconsin obtains 10 percent of its electricity in 2015 from renewable resources. The Commission is also responsible for applying the energy priorities statute, Wis. Stat. § 1.12, when making its decisions. This statute requires that the Commission prioritize renewable sources of energy over non-renewable sources.

The Commission has taken the lead, supported by the utility Commissions of Iowa, Minnesota, North Dakota, South Dakota, Manitoba, and several industry and nonprofit organizations to research, develop, contract for and successfully launch the Midwest Renewable Energy Tracking System (M-RETS). M-RETS allows utilities to effectively and efficiently track and report renewable generation in compliance with the statutory requirements and provides a platform for the trading of the Renewable Resource Credits created within the system.

Wisconsin can help meet the GHG emission reduction targets recommended by the GWTF by curbing demand and substantially increasing the deployment of renewable energy technologies, above and beyond the current RPS goal. Accordingly, the GWTF recommended enhancements to the RPS statutory requirements including new, more ambitious targets: 10 percent renewable electricity by 2013; 20 percent by 2020; and 25 percent by 2025.

The Commission recognizes that dramatic increases in the deployment of renewable energy technologies could pose extraordinary challenges across a range of issues, especially in regards to cost and transmission system impacts. However, those challenges are not insurmountable and the Commission is prepared to work with utilities and other stakeholders to tackle the issues.

The Commission recently opened docket 5-EI-148, Investigation on the Commission's Own Motion Regarding Advanced Renewable Tariff Development. This investigation, which is also based on a recommendation of the GWTF, is exploring the potential to encourage deployment of renewable resources through price incentives rather than mandatory quotas such as the RPS. There is a growing body of research, mostly from Europe, that suggests price incentives may be more effective than quotas at encouraging rapid, widespread, and cost-effective deployment of renewable energy technologies. The Commission has previously approved experimental price incentives for renewable energy, but it is now taking a more comprehensive look at whether renewable tariffs could be used more widely as an alternative or supplement to Wisconsin's RPS policy.

Fossil Fuels

Wisconsin is heavily dependent on fossil fuels, especially coal, for electric power. Nearly 86 percent of Wisconsin's generating capacity uses fossil fuels. In 2006, 64 percent of the electricity used in the state came from fossil fuel plants located in Wisconsin. In addition, Wisconsin imported 17 percent of the electricity it used in 2006, some of which was also derived from fossil fuels. This Commission recognizes that coal and other fossil fuels will continue to play an important part in meeting Wisconsin's electricity needs for the foreseeable future. However, the Commission expects that the cost advantages of fossil fuels may be reduced or even overtaken by the added costs of compliance with mandatory GHG emission constraints.

The Commission is particularly interested in ongoing research and development of technologies to capture and sequester GHG emissions from fossil fuel combustion. Last year the Commission opened docket 5-EI-145, Investigation to Explore the Potential for Geologic Carbon Sequestration for Carbon Dioxide produced by Wisconsin's Electricity Generation Fleet. If and when these technologies become commercially available, they may enable some areas of Wisconsin to continue to take advantage of existing fossil fuel infrastructure as well as the abundant reserves of coal in the U.S. while minimizing air pollution and climate change impacts. Unfortunately, as the Commission noted in its Order last year on the Oak Creek Power Plant Pollution Controls docket, "...(C)lean coal technologies are not yet available, nor are they likely to be available for an in-service date of 2019..." This issue also arose in the Commission's Order on the recent Nelson Dewey 3 case: "...(T)he technology for carbon capture and sequestration is so experimental and so far from commercial viability that the cost of retrofitting plants with carbon capture and sequestration technology is unknown."

Every power plant is ultimately retired when it no longer becomes cost effective to operate or renovate it. If and when mandatory GHG emission constraints are enacted, one of the key decisions for fossil fuel power plants may be whether early retirement is the best option. The public interest may be best served if the least efficient and least cost–effective power plants in the state are the first to be retired. The Commission encourages the utilities to explore a coordinated approach to this issue, while recognizing that the autonomy and the varying needs of each individual electric utility are critical determinants in each specific scenario.

Nuclear Power

Nuclear power is an important part of Wisconsin's current electric generation mix. Approximately 10 percent of Wisconsin's generating capacity is powered by nuclear energy. In 2006, 16 percent of the electricity used in the state came from nuclear power plants located in Wisconsin. In addition, some of the electricity imported into Wisconsin was generated at nuclear power plants in other states.

Nuclear power plants can provide reliable baseload electric generation with no direct emissions of GHG. However, concerns about nuclear safety and nuclear waste storage are shared by a substantial portion of the population and these concerns will not disappear overnight. For this reason, there is lively debate on the appropriate role of nuclear power against a backdrop of climate change. The Commission views this debate as a healthy contribution to the search for energy and climate solutions.

Current Wisconsin law (Wis. Stat. § 196.493) prevents the Commission from issuing a Certificate of Public Convenience and Necessity (CPCN) to a nuclear power plant unless a federally licensed facility, or a facility outside of the U.S. which the Commission determines will satisfy the public welfare requirements of the people of Wisconsin, with adequate capacity to dispose of high–level nuclear waste from all nuclear power plants operating in this state will be available, as necessary, for disposal of the waste. Given the history and current status of efforts to establish the first federally licensed nuclear waste repository, it is the view of the Commission that this condition for issuing a CPCN is unlikely to be met in the near future.

The GWTF has recommended very specific modifications to the current law that would relax the limitation on CPCNs for nuclear power plants. The Commission looks forward to helping inform the debate on this important topic.

Transmission

Regardless of the technologies used to generate electricity, there remains the need to transmit the power to end users. The decisions that Wisconsin utilities and this Commission make about transmission will have a significant impact not only on rates and reliability, but also on GHG emissions. For example, the Commission sees opportunities to reduce GHG emissions by making investments to improve the efficiency of Wisconsin's transmission grid. A federal interagency report, *U.S. Climate Change Technology Program – Technology Options for the Near and Long Term (November 2003)*, estimated that the U.S. generated 7.2 percent more electricity in 1995 than it actually used, due to losses in the transmission and distribution system. A number of technologies and materials have been developed that can reduce these losses, thereby reducing generation needs and the associated GHG emissions. Some of these technologies and materials have been deployed in Wisconsin, but this is an area where significant improvements are still possible.

Just as transmission decisions affect emissions, the reverse is also true—decisions about GHG emission reduction strategies will have implications for transmission. The pressure to add more and more renewable energy installations to the grid complicates transmission planning. Fossil fuel power plants can be sited where the need is greatest, but some renewable technologies can only be sited where the resource is abundant. Any large distance between the load and the resource will increase the need for transmission lines. And intermittent renewable resources such as wind turbines pose unique challenges for grid stability and reliability because these assets are not fully dispatchable. For example, the Commission recently completed an investigation into the potential to site wind turbines on the Great Lakes. One of the conclusions of that study is that large offshore projects will probably make more economic sense than small offshore projects, but large projects may require enhancements to the existing transmission infrastructure.

Another example of a strategy that might help this state meet GHG emission reduction goals would be for Wisconsin utilities to build (or purchase electricity from) new baseload coal-fired power plants *outside* Wisconsin that are sited near a coal mine and an appropriate geologic carbon sequestration site. However, in order for that electricity to meet the needs of Wisconsin utility customers, new transmission capacity might be required. This scenario, if it ever develops, could have substantial implications for transmission infrastructure and costs. The Commission is exploring this possibility as part of the previously mentioned investigation of carbon capture and sequestration.

Finally, existing methods for allocating the costs of new transmission lines may place new renewable resources at a disadvantage compared to existing fossil fuel power plants. Most of the transmission issues that directly or indirectly affect GHG emissions are regional in nature. Although the Commission regulates Wisconsin's transmission-owning utilities, it cannot resolve most of these issues by acting in isolation. For this reason, the Commission plays an active role in monitoring the work of the Midwest Independent Transmission System Operator, Inc. (MISO) where many of these issues are front and center. The Commission is also involved in multi-state transmission policy discussions through its work with the Midwestern Governors Association's Energy Initiative, and more specifically *via* the Upper Midwest Transmission Development Initiative and the efforts of the Organization of MISO States.

Cost Impacts

As the economic regulator of Wisconsin's public utilities, the Commission seeks to ensure that adequate and reasonably priced service is provided to utility customers in an efficient and environmentally responsible manner. That mission has not changed.

The cost of electric service, like nearly all services, has historically increased with time for a variety of reasons and will likely continue to do so. Mandatory GHG emission constraints will probably exacerbate the upward pressure on rates. But this Commission also sees two countervailing trends that offer some hope for those concerned about the impact of GHG regulation on energy prices.

First, energy efficiency and conservation measures make it possible for many residences and businesses to reduce their total energy consumption. As a result, some ratepayers may see a net decrease in their utility bills even as GHG regulations drive up the cost of each unit of purchased electricity. This possibility was confirmed by computer modeling completed by the GWTF.

Second, recent trends suggest that renewable energy technologies will, over the course of time, become increasingly cost effective and technically feasible and thus more cost-competitive with fossil fuel technologies. This trend will almost certainly be accelerated and amplified if mandatory GHG emission constraints are enacted.

Historically, this Commission assigned no present or future cost to GHG emissions when reviewing the costs and benefits of electric utility projects. This assumption factored into the decisions for most of the electric infrastructure projects that are still serving Wisconsin today. In more recent cases, the Commission assumed no cost for GHG emissions as a default or base case, but also ran sensitivity analyses that monetized GHG emissions in future years based on possible GHG regulations. Although that was a step in the right direction, it is increasingly obvious that the Commission cannot afford to treat mandatory GHG emission constraints as an unlikely "hypothetical." In the recent Nelson Dewey 3 case, the Commission's Order stated unambiguously that "The cost to ratepayers of controlling greenhouse gas emissions cannot be ignored." It is the view of this Commission that all future applications for electric utility projects should assume monetization of GHG emissions as a base case, not just in sensitivity runs.

The Way Forward

One of the most common criticisms this Commission hears from opponents of aggressive, mandatory GHG reduction targets (such as those recommended by the GWTF) is that nobody knows whether the targets could realistically be met or what it might cost to do so. While the Commission recognizes that reducing carbon emissions may be costly, this is not an argument against action. The Commission will seek to directly address this question by developing and analyzing some plausible scenarios for a carbon-constrained energy future in Wisconsin that is consistent with the perspectives offered herein.

Within two months of publication of this SEA, Commission staff will prepare a detailed analysis of plausible least-cost scenarios in the year 2020 under a national cap and trade regime, describing plant additions, retirements, repowering or fuel switching, any other measures, and costs above "business as usual." The report shall be based on the best available information regarding the likely structure and implementation of a national or regional cap and trade regime. The report shall be updated to reflect the adoption of legislation or policies related to such a regime. The analysis shall be, to the extent possible, statewide in scope. The staff report will be made available for comments from utilities and other interested stakeholders. The Commission directs staff to develop this analysis based on the following assumptions:

- Business As Usual Assumptions
  - Capacity planning reserve margins consistent with Commission policy;
  - RPS requirements as specified in current law;
  - No mandatory GHG emission reduction requirements;
  - New nuclear power plants are not an option.

- Base Case Assumptions
  - Business As Usual Assumptions, plus each utility is regulated within a national GHG cap and trade program as follows:
    - Emissions of each electric utility capped in 2012 at the same level as the utility's average emissions in the three years from 2004 through 2006;
    - Emissions in 2020 must be 20 percent below the utility's average emissions in the three years from 2004 through 2006;
    - Emissions cap declines linearly in the interim years between 2012 and 2020;
    - All allowances distributed via auction (no allocations);
    - Purchased allowances can be banked and used in any future year;
    - Offsets and early action credits are not available.

- Sensitivity Cases
  - Demand growth lower or higher (perhaps due to electric vehicles) than business as usual assumption;
  - Carbon price lower or higher than base case assumption
  - Enhanced RPS as recommended by GWTF;
  - New nuclear power plants are an option after 2020;
  - Carbon capture and storage technologies are available at certain existing generators after 2020;
  - Allowances distributed via a combination of auction and allocation, with a ramp-up to a majority of distribution via auction by 2020;
  - Solar photovoltaics are allowed to meet the RPS;
  - Energy storage is available in Wisconsin;
  - Variations of discount rates;
  - Other: staff may develop additional sensitivity cases deemed appropriate by the Administrator of the Gas and Energy Division.

The assumptions in these scenarios should not be interpreted to represent the Commission's position on any of the relevant policy issues, nor are they predictions of what the future holds. Some of the assumptions, such as assuming 100 percent auction of GHG allowances, are intended solely to simplify the analysis of scenarios.

Equally importantly, these scenarios are not meant to serve as a substitute for the Advance Plans of the past. The Commission will continue to make regulatory decisions on a case-by-case basis using existing procedures and criteria. The sole purpose of these scenarios is to develop an up-to-date assessment of how Wisconsin utilities might go about meeting medium-term GHG emission reduction targets such as those recommended by the GWTF or proposed by the President and some members of Congress.

Conclusion

This Commission accepts its own ongoing responsibilities to help the utilities address climate change. It will continue to work with Wisconsin's public utilities to find effective solutions that serve the public interest and minimize adverse economic impacts on ratepayers and utility shareholders.

Individual Commissioner Comments

COMMISSIONER AZAR'S COMMENT

As with the rest of the nation, Wisconsin is at a crossroads with respect to energy policy. Our current methods of generating and using electricity are likely to change dramatically and some may soon become obsolete. I believe that this Commission must endeavor to facilitate a transformation of the Wisconsin electric industry in a manner that will improve Wisconsin's prosperity.

Wisconsin cannot afford to take on this transformation under the current regulatory framework where we review plans on a utility-by-utility basis. I believe that such a piecemeal approach will ultimately impose significant and unnecessary costs on Wisconsin ratepayers. Instead, Wisconsin must work on a statewide and, indeed, a regional basis to optimize all the resources available to us. In my view, this is the only way Wisconsin can reasonably meet the challenges of the new energy world at our doorstep.

I applaud efforts to increase the substance of the SEA. For example, as a result of this SEA, the Commission staff will develop plausible scenarios for a carbon-constrained future in Wisconsin. However, as noted in this Perspective from the Commission, the scenarios found in this document "are not meant to serve as a substitute" for the past statewide planning efforts. The fact is, since the Commission's planning abilities were limited in the late 1990s, we have attempted to apply inadequate tools as a proxy for planning. At this point in history, when massive changes in energy policy are imminent, this limited authority is untenable.

If Wisconsin is to truly be strategic about its energy policy, it is essential that the Legislature take action to provide the Commission with the planning tools that we need to ensure that Wisconsin's ratepayers will continue to have the safe, reliable and cost-effective electric service they deserve.

STRATEGIC ENERGY ASSESSMENT REPORT

2008-2014 Electricity Issues

STUDY SCOPE

The Public Service Commission of Wisconsin (Commission or PSC) is required to prepare a biennial Strategic Energy Assessment Report (SEA) that evaluates the adequacy and reliability of Wisconsin's current and future electrical supply.

The SEA intends to identify and describe:

- All large electric generating facilities for which an electric utility or merchant plant developer plans to commence construction within seven years;
- All high-voltage transmission lines for which an electric utility plans to commence construction within seven years;
- Any plans for assuring that there is an adequate ability to transfer electric power into or out of eastern Wisconsin, and the state as a whole, in a reliable manner;
- The projected demand for electric energy and the basis for determining the projected demand;
- Activities to discourage inefficient and excessive power use;
- Existing and planned generation facilities that use renewable energy sources.

The SEA is required by statute to assess:

- The adequacy and reliability of purchased generation capacity and energy to serve the needs of the public;
- The extent to which the regional bulk-power market is contributing to the adequacy and reliability of the state's electrical supply;
- The extent to which effective competition is contributing to a reliable, low-cost, and environmentally sound source of electricity for the public;
- Whether sufficient electric capacity and energy will be available to the public at a reasonable price.

The SEA must also consider the public interest in economic development, public health and safety, protection of the environment, and diversification of energy supply sources.

STUDY METHODOLOGY AND LIMITATION

Under statutory and administrative code requirements, every electricity provider and transmission owner must file specified historic and forecasted information. The draft SEA must be distributed to interested parties for comments. Subsequent to hearings and receipt of written comments, the final SEA is issued. In addition, an Environmental Assessment, which includes a discussion of generic issues and environmental impacts, will be issued in connection with the SEA.

This fifth SEA covers the years 2008 through 2014. During the past year, ten large Wisconsin-based investor-owned utilities, cooperatives, municipal electric companies, and other electricity and transmission providers submitted historic information regarding statewide demand, generation, out-of-state sales and purchases, transmission capacity, and energy efficiency efforts. In addition, these entities provided forecasted information through 2014. The Commission also recently requested utilities to provide information related to CO_2 emissions. Responses have been incorporated into this final report.

The SEA is an informational study that provides the public and stakeholders with relevant trends, facts and issues affecting the state's electric industry. The SEA is not a prescriptive report, meaning that the ideas, facts, projects, and policy discussions contained in this report have not been approved for implementation or construction by the Commission. State law precludes such action, specifically Wis. Stat. § 196.491(3)(dm). Should a specific topic warrant further attention with the intent of Commission action, the Commission must take additional steps as authorized by law.

OTHER STATE INITIATIVES

The GWTF was created by Governor Jim Doyle pursuant to Executive Order 191. The duties of the GWTF pursuant to the Executive Order are as follows:

- Present viable, actionable policy recommendations to the governor to reduce greenhouse gas emissions in Wisconsin and make Wisconsin a leader in implementation of global warming solutions;
- Advise the governor on ongoing opportunities to address global warming locally while growing our state's economy, creating new jobs, and utilizing an appropriate mix of fuels and technologies in Wisconsin's energy and transportation portfolios;
- Identify specific short-term and long-term goals for reductions in greenhouse gas emissions in Wisconsin that are, at a minimum, consistent with Wisconsin's proportionate share of the reductions that are needed to occur worldwide to minimize the impacts of global warming.

The Final Report of the GWTF, approved in July 2008, discusses several concerns and makes recommendations on the following key issues:

- Enhanced Energy Efficiency Programs
- Policy Changes Recommended in Utility Ratemaking
- Aligning Public and Private Interests for Energy Conservation and Efficiency
- Improved and Innovative Rate Design
- Demand Response and Load Management
- Residential and Commercial Energy Efficient and Green Building Codes
- State Government as Leader
- Energy Efficiency and Safety through Lighting for Wisconsin Rental Properties
- Comprehensive Initiative to Support Voluntary Long-Term Greenhouse Gas Emissions Reductions
- Great Lakes Wind Study
- Wisconsin Geologic Carbon Sequestration Study
- Wind Siting Reform

The Final Report of the GWTF sets forth recommendations that focus on supporting individual, community and business early action, advances Wisconsin's strong leadership position on energy efficiency and conservation by moving the state's goals and programs to an even higher level, and initiates several studies and takes other actions necessary to advance our understanding of key issues related to increasing the state's renewable energy resources and otherwise reducing the carbon emissions associated with electric generation.

Executive Summary

DEMAND AND SUPPLY OF ELECTRICITY

- The overall trend in peak demand growth is estimated by the state's utilities to be approximately 2.10 percent per year through 2014. This represents incremental demand increases roughly equivalent to a major power plant of about 500 megawatts (MW) every two years.
- New generation and transmission will reduce Wisconsin's reliance on the currently congested transmission grid connections to Illinois.
- Generation ownership has changed. Independent power producers have been active in developing wind projects in Wisconsin. Generation planning shows no new baseload generation is needed during this SEA planning period on a statewide basis.
- Transmission planning may show more EHV is needed in order to bring wind generation to Wisconsin.
- Greenhouse gas emissions need addressing due to climate change policy expectations.

MARKET ANALYSIS AND PLANNING RESERVE MARGIN FORECASTS

- It is expected that the current and ongoing transmission system expansion and improvements will greatly enhance the ability to move electricity into and within Wisconsin by 2010.
- Significant approved new generation coming online is expected to keep planning reserve margins near or above 19 percent through 2012. As of right now, based on already approved payments the planning reserve margin for 2014 is expected to be nearly 12 percent. This number is expected to increase as more energy efficiency and generation is proposed.
- The market for purchased generation capacity and energy continues to evolve.
- The Commission will continue to work on the issues associated with balancing environmental protection with reliable and affordable electric energy.

RATES

- Fuel prices and purchased power cost increases, as well as construction costs for generation and transmission facilities, are the significant drivers of recent rate increases.
- Rate increases can be mitigated somewhat with energy conservation, innovative utility financing related to environmental trust fund programs, and other new rate options.

ENERGY EFFICIENCY AND RENEWABLE RESOURCES

- 2005 Wisconsin Act 141 was recently enacted and will substantially revise the funding and structure of energy efficiency and renewable resource programs in Wisconsin. The legislation is based on the recommendations of the Governor's Task Force on Energy Efficiency and Renewables.

ENVIRONMENTAL ISSUES

- The importance of energy efficiency, conservation, and load control to reduce Wisconsin's energy costs and environmental impacts is shown in the findings of the GWTF, as well as analysis in this final SEA report.

GLOBAL WARMING TASKFORCE RECOMMENDATIONS

- The GWTF recommends policies to aggressively promote much greater energy conservation and efficiency.

NEXT STEPS

- The Commission stands ready to assist the governor and the legislature in doing its part to provide independent technical assessments as Wisconsin moves forward with changing energy use.

Electric Demand and Supply Conditions in Wisconsin

An electricity provider is defined for SEA purposes in Wisconsin Administrative Code as any entity that owns, operates, manages, or controls or who expects to own, operate, manage, or control electric generation greater than 5 megawatts (MW) in Wisconsin. For simplicity's sake, Figure 1 shows generators greater than 10 MW. Electricity providers also include those entities providing retail electric service or who self-generate electricity for internal use with any excess sold to a public utility. Major retail electricity providers and/or transmission owners that submitted demand and supply data for this SEA include: American Transmission Company LLC (ATC), Madison Gas and Electric Company (MGE), Manitowoc Public Utility (MPU), Northern States Power-Wisconsin (NSPW) (d/b/a Xcel Energy, Inc. (Xcel)), Superior Water, Light and Power Company (SWL&P), Wisconsin Electric Power Company (WEPCO) (d/b/a We Energies), Wisconsin Power and Light Company (WP&L) (d/b/a Alliant Energy), and Wisconsin Public Service Corporation (WPSC).

These major retail providers were required to include supply and demand data for any wholesale requirements that they have under contract. This action streamlined data reporting and reflected current market activities. Demand and supply data were also provided by Dairyland Power Cooperative (DPC) and Wisconsin Public Power, Inc. (WPPI) on behalf of their member cooperatives and municipal utilities.

Figure 1 Map of Major Electric Generation Plants in Wisconsin

Table 1 shows the aggregated responses of the entities providing data for this final SEA. The Commission requires providers to maintain 14.5 percent[1] future planning reserve margins. Data for later years should be considered preliminary, because of the longer-term outlook and the very nature of contracting for supply arrangements.

Table 1 shows that for the past few years reserve margins during the peak period have been around 20 percent. This value shows that Wisconsin has operated with a healthy level of reserves during the summer peak.[2]

Table 1 Aggregated Responses of Entities Providing Data for this Final SEA

Line		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
					Forecasted Planning Values						
Summer Peak Electric Demand (MW)											
				Last Full Year							
	Date of Peak Load			31-Jul							
	Date of Peak Load	9-Aug	31-Jul	1-Aug							
1	Peak Load Data & Forecast (non-coincident)	14,395	14,993	14,535	13,731	15,831	16,066	16,389	16,678	16,955	17,240
2	Direct Load Control Program	-37	-99	-88	-59	-170	-171	-176	-179	-184	-186
3	Interruptible Load	-315	-243	-164	-315	-669	-669	-690	-691	-698	-702
4	Capacity Sales Including Reserves	770	732	926	725	710	650	584	644	701	757
5	Capacity Purchases Including Reserves	-719	-725	-652	-603	-704	-571	-529	-560	-591	-622
6	Miscellaneous Demand Factors	-570	-553	-555	-553	-590	-592	-590	-590	-526	-527
7											
8	**Adjusted Electric Demand**	**13,524**	**14,105**	**14,002**	**12,926**	**14,407**	**14,712**	**14,988**	**15,301**	**15,657**	**15,960**
Electric Power Supply (MW)											
9	Owned Generating Capacity, Used For Wisconsin Load	12,356	12,781	12,831	11,855	12,914	13,287	13,928	14,584	14,828	15,431
10	Merchant Power Plant Capacity Under Contract, Used For Wisconsin Load	3,157	3,790	3,518	4,043	3,505	3,507	3,481	3,212	2,492	1,921
12	New Owned or Leased Capacity Additions	664	60	0	1,057	309	639	619	300	595	353
17	Net Purchases Without Reserves	543	577	284	260	254	260	295	327	256	256
18	Miscellaneous Supply Factors	-302	-214	-234	-290	-224	-236	-200	-289	-257	-240
19											
20	**Electric Power Supply**	**16,418**	**16,994**	**16,399**	**16,924**	**16,758**	**17,457**	**18,122**	**18,135**	**17,914**	**17,721**
Calculated Data											
21	Reserve Margin	21.4%	20.5%	17.1%							
22	Planning Reserve Margin				30.9%	16.3%	18.7%	20.9%	18.5%	14.4%	11.0%
Transmission Data											
25	Resources Utilizing PJM/WUMS-MISO Interface	925	990	940	830	585	585	585	385	85	85

UTILITIES' PERSPECTIVE—PEAK DEMAND AND SUPPLY

Demand

The Commission compiled substantial information on peak electric demand and energy use for this report. Demand is a measure of instantaneous use measured in MW. Energy is a measure of the volume of electricity used measured in megawatt hours (MWh). Demand for electricity fluctuates both throughout the day and throughout the year. In any day there

[1] The 14.5 percent value is a new requirement adopted by the PSC in summer 2008. See docket 5-EI-141 for more information.

[2] The joint public intervenors (JPI) point out that measurement of the reserve margin in Table 1 may understate the actual reserve margin because the calculation excludes demand management resources that were not actually used. The calculations in Table 1 are consistent with the Commission's practice in past SEAs, which is founded in the reliability practices that were used by the Mid-America Interconnected Network (MAIN). As Wisconsin's planning efforts mature, and as more demand management practices are incorporated into the marketplace, the methodology of this calculation may need to be revisited to ensure that planners and policy makers are working with the most accurate assessment of all of Wisconsin's resources.

are peak hours of demand. In the summer the demand usually has one peak in the afternoon hours. In the winter it is common to have a morning and an evening peak. Over the course of a year demand for electricity is higher in the summer, lowest in the spring and autumn "shoulder" months, and a smaller peak occurs in the winter. Table 2 shows historic monthly peaks since 1997 and forecasted monthly peaks.

Table 2 Assessment of Electric Demand and Supply Conditions, Monthly Non-Coincident Peak Demands, MW

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Historical												
1997	9,948	9,386	9,132	8,833	8,518	11,025	11,343	10,265	9,866	9,657	9,598	9,912
1998	10,077	9,326	9,334	8,674	10,286	11,482	12,094	11,411	9,867	9,274	9,394	10,487
1999	10,492	9,531	9,540	8,850	9,108	11,554	13,120	11,331	11,402	9,167	9,953	10,881
2000	10,245	10,004	9,367	9,125	9,986	10,924	11,727	12,726	11,778	9,559	10,082	10,937
2001	10,300	10,032	9,722	9,179	9,742	11,800	13,575	13,870	10,898	9,684	9,805	10,268
2002	10,286	9,965	10,111	9,924	10,381	12,782	13,518	13,454	13,211	10,445	10,080	10,857
2003	10,739	10,498	10,291	9,602	9,048	12,725	13,319	13,694	11,937	10,136	10,450	11,302
2004	10,924	10,384	10,091	9,400	10,273	12,486	12,958	12,437	12,161	9,902	10,557	11,478
2005	11,127	10,678	10,433	9,610	10,000	14,020	13,832	14,323	13,224	11,912	10,833	11,581
2006	10,622	10,556	10,174	9,550	11,527	12,559	15,006	14,507	11,060	10,320	10,909	11,553
2007	10,958	11,419	10,682	9,946	11,343	13,834	14,163	14,461	13,693	12,033	11,091	11,503
Forecasted												
2008	11,409	11,367	10,632	10,094	9,732	12,527	13,580	13,350	13,232	10,614	11,346	12,060
2009	11,840	11,503	11,169	10,502	11,485	14,365	15,664	15,590	13,452	11,226	11,493	12,225
2010	11,982	11,654	11,346	10,665	11,687	14,575	15,893	15,820	13,647	11,373	11,624	12,364
2011	12,278	11,929	11,560	10,885	12,043	14,972	16,212	16,183	13,998	11,563	11,855	12,670
2012	12,461	12,083	11,739	11,058	12,236	15,229	16,498	16,464	14,257	11,737	12,024	12,844
2013	12,619	12,247	11,907	11,208	12,431	15,478	16,773	16,726	14,456	11,903	12,179	13,019
2014	12,799	12,425	12,085	11,373	12,629	15,741	17,055	17,003	14,698	12,070	12,344	13,202

Using the projections provided by the entities submitting data for this SEA, this pattern of winter and summer peaks is expected to continue into the future. While actual demand will remain dependent upon weather, the overall statewide trend is expected to show continued growth in peak demand, estimated by the state's utilities combined to be approximately 2.10 percent per year through 2014.[3] The recession in progress is likely to have a significant, short-term effect on energy sales. However, peak demand is much more responsive to weather, and it is not clear at this time that the recession will have the same percentage impact or peak demand that it has on total energy sales.

On June 22, 2007, the Commission held a technical conference, attended by the Commissioners, where stakeholders offered comments and recommendations regarding generation and transmission planning in Wisconsin. Comments were varied, and included:

- Efficient resource planning requires the consideration and integration of all resource options to identify least-cost alternatives that can be expected to achieve a broad range of desired objectives including environmental value;

[3] As part of this SEA, Commission staff has not prepared its own forecast for peak demand. In a later section, under generation planning, Commission staff does utilize energy and demand forecasts with somewhat lower growth rates than the combined values provided by the state's utilities.

- The process should be collaborative and transparent, and facilitate conversations between states;
- Planning should be regional;
- Planning should integrate baseload generation and renewables;
- The Commission should participate in the MISO transmission planning process;
- The Certificate of Authority/Certificate of Public Convenience and Necessity process requires integration of energy conservation, generation including renewables, and transmission options;
- The Commission should revisit the drivers behind potential price increases and identify optimal balance between meeting policy objectives, environmental compliance, and rates;
- The Commission should adopt a staged approach to resource planning and implementation by forecasting electricity needs, assessing energy efficiency demand response and supply resources, and integrating all resources.

PROGRAMS TO CONTROL PEAK ELECTRIC DEMAND

The state's utilities have two forms of peak load management, direct load control and interruptible load. Peak load management is removing load from the system at times when utility resources for generation are not able to meet customer demand for energy. These programs were traditionally expected to be used primarily in the summer months, usually on very hot days when demand for electricity is at its highest. In recent years, under certain circumstances, when the winter peak demand for electricity outpaced available generation, these programs have been used to assure a balance between demand and available supply.

Direct load management gives the utilities the ability to take off the system electric demand such as residential air conditioners. When a utility implements direct load control, affected customers who volunteered to participate in the program receive a credit on their utility bill. Prior SEAs and Table 1 show that direct load control has been used very sparingly from 2005 through 2008; between 37 and 88 MW of direct load control were called upon. As shown in Table 3, the MW of direct load control available to utilities is much greater than what was called upon.

The second form of load management is the use of interruptible load for industrial customers. An industrial customer choosing to select an interruptible load tariff receives a lower electric energy rate (cents per kilowatt hour (kWh)) by agreeing that load may be interrupted during periods of peak demand on the system. A utility will notify an industrial customer on an interruptible load tariff that its load will be taken off the system at a specific time. Again, the actual MW of load that are interrupted in a given year is less than the MW of load that are covered by interruptible tariffs. In any given year, the need to utilize this form of load control will depend upon generation supply that is available on the days when peak demand happens or when available generation is tight due to planned or unexpected (forced) outages. By 2014 interruptible load is expected to be approximately 4 percent of projected electric power supply.

Table 3 Available Amounts of Programs and Tariffs to Control Peak Load, MW

Year	Direct Load Control (MW)	Interruptible Load (MW)
	Historical	
1997	169	677
1998	162	794
1999	173	773
2000	169	664
2001	185	637
2002	200	583
2003	186	554
2004	193	628
2005	225	693
2006	178	807
2007	175	772
	Forecasted	
2008	171	669
2009	170	669
2010	171	669
2011	176	690
2012	179	691
2013	184	698
2014	186	702

PEAK SUPPLY CONDITIONS: GENERATION AND TRANSMISSION

As noted in Table 4, the reserve margin for 2008 was 31 percent. Even with the rather robust growth in peak summer demand indicated by the utilities of approximately 2.10 percent per year through 2014, the significant approved additional new generation coming online through 2010 is expected to keep planning reserve margins near or above 18 percent through 2012. Since the requirement to carry 14.5 percent planning reserves has been met, generation adequacy has been successfully addressed. Figure 1 is a map of major electric generation facilities for Wisconsin.

Table 4 Forecast Planning Reserve Margins from SEA

Planning Year	Final SEA 2000	Final SEA 2002	Final SEA 2004	Final SEA 2006	Final SEA 2008
2001	17.95%				
2002	17.44%				
2003		19.07%			
2004		20.86%	18.30%		
2005			17.43%		
2006			14.97%		
2007			16.13%	18.20%	
2008			12.80%	18.90%	30.90%
2009			10.00%	16.40%	16.30%
2010			11.00%	17.50%	18.70%
2011				17.20%	20.90%
2012				17.40%	18.50%
2013					14.40%
2014					11.00%

Note: The SEA was expanded to cover seven years of forecast data in 2004; prior SEAs only examined two years.

Table 4 illustrates planning reserve margins over time. Table A-1, shown in the appendix of this report, shows new generation facilities and upgrades expected to be in operation or under construction by 2014. It does not include the utilities' listed retirements, as the timing of these is more uncertain. Nor does it include 3-5 MW de-ratings of coal units due to installation of additional air pollutant controls (the two Pleasant Prairie units would each be de-rated by 8 MW). Table A-1 includes three Commission-approved baseload serving units, an intermediate load serving unit, and three wind projects. Since the last such SEA listing, three combined-cycle units, a cogeneration facility, and combustion turbines are now operational. The Commission rejected the Nelson Dewey proposed project, a baseload coal unit, in fall 2008. Therefore, the list in Table A-1 must be viewed for what it is: utility requests for new generation, and not necessarily projects approved by the Commission. Those projects that have been approved are noted, however.

NEW GENERATION

Wisconsin is in a multi-year expansion period for electric generation that will expand in-state generation capacity by over 3,000 MW through 2014. Over the past three years, from 2005 through 2008, over 1,600 MW of additional, new generation capacity has been brought into service.

Looking forward, new facilities will include three new, large coal-fired units with over 1,700 MW of capacity, the first new, super-efficient, coal-fired baseload plants in Wisconsin since the early 1980s. Almost 750 MW of new wind powered generation are expected to become part of the Wisconsin generation mix between 2008 and 2014, over 300 MW of new wind projects have been approved at wind farms in Wisconsin. Other wind projects in Iowa and Minnesota will further diversify the location of wind resources for the benefit of Wisconsin ratepayers. An expected 575 MW of combined-cycle capacity and 55 MW of combustion turbine capacity is projected to be fired by natural gas. A 90 MW generation addition from an upgrade of a nuclear powered plant, now all merchant owned, is also expected. Figure 2 illustrates new utility-owned or leased generation capacity for this SEA reporting period. Figure 3 shows the MW capacity by fuel type as of July 2007. Figure 4 shows the MWs of energy produced by fuel type for 2006.

Figure 2 New Utility-Owned or Leased Generation Capacity, 2008-2014

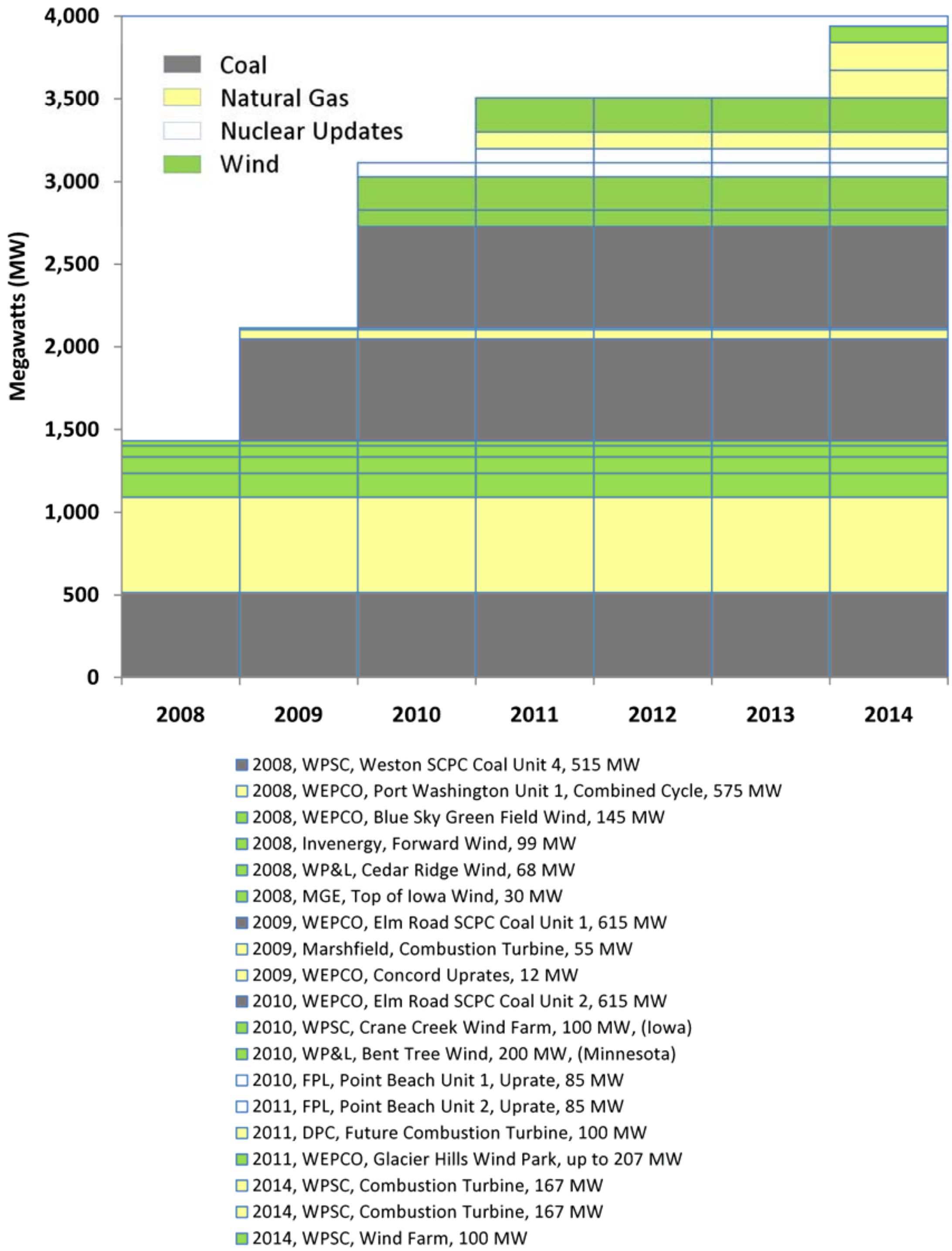


Figure 3 Capacity by Fuel Type as of July 2007 (MW)

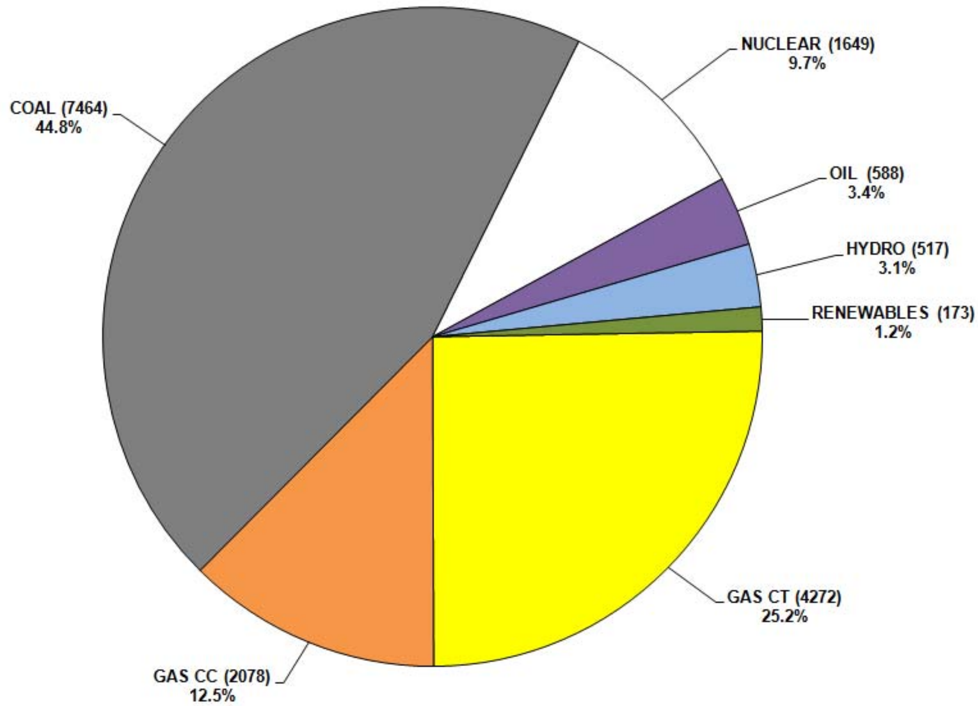
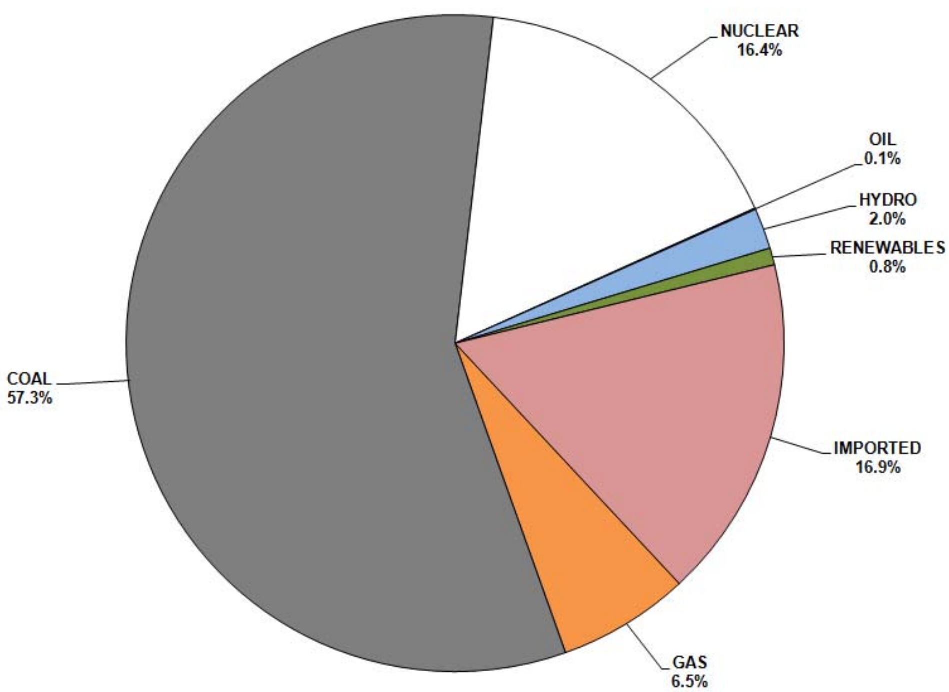


Figure 4 Actual Generation by Fuel for 2006 (MWh)



COMMISSION STAFF ANALYSIS—GENERATION PLANNING AND MODELING

The SEA is not prescriptive and its purpose is to identify issues facing Wisconsin's energy future and explore opportunities for meeting future energy challenges. To better understand these future challenges for this report, Commission staff utilized the Electric Generation and Expansion Analysis System (EGEAS) for modeling similar to how planning studies have been utilized by Wisconsin utilities for 20-plus years.

EGEAS selects the optimal combination of generation resources to be constructed in the future, based on forecasted demand and energy, cost of construction for new generation, fuel costs, variable operations and maintenance (O&M) expenses, and fixed O&M expenses for all generating resources—existing, committed, and new generating units. The model can also be forced to pick certain units in any given year. This feature is used to place wind units to meet the requirements of Wisconsin's renewable portfolio standard (RPS). The new generating units that the model could choose to meet demand include generic coal-fired plants, generic combined-cycle gas-fired plants and combustion turbines, generic wind turbines, and single-year energy purchases.

The analysis summarized here performs a study of the entire ATC footprint, which accounts for 85 percent of Wisconsin's energy needs. The aggregate analysis eliminates some of the lumpiness seen with bringing large generating units on line for individual utilities. EGEAS identifies a need, but does not determine where a power plant should be built, which utility needs the power, or where power lines are routed.

The EGEAS data set used by Commission staff was created by combining available data from the ATC utilities (WEPCO, WPSC, WP&L, MGE and WPPI). One of the reasons this footprint was chosen is that 2006 hourly load data was available for the ATC footprint.

Additionally, while NSPW imports the bulk of the energy necessary to meet its load, this import requirement is partially offset by the export from DPC based on reported 2006 data. The additional energy needs of a Wisconsin footprint (including NSPW and DPC) could be approximately modeled in a future SEA proceeding, if so desired. The EGEAS planning period is 2006-2035, with a 30-year extension period.

In today's world of Regional Transmission Organizations (RTO), electric utilities have the option of locating their generation facilities outside of their service territory and transporting the power via the RTO's transmission facilities. This may or may not be more cost-effective than locating a generating facility in a utility's service territory. One needs to compare the fuel transportation cost savings (mine mouth coal) or higher capacity factor (wind) of building that generation in locations farther away with any additional transmission infrastructure or locational marginal pricing (LMP) costs of locating generation within the electric utility's service territory. Issues associated with transmission are discussed later in this final SEA.

Specific modeling assumptions used by Commission staff are discussed in the following sections.

Emission Monetization and Control

For all EGEAS modeling scenarios used for this SEA analysis, CO_2, SO_2 ($400 per ton), NO_x ($2,000 per ton) and mercury ($35,000 per pound) are monetized. For all modeling scenarios, except the high CO_2 cost scenario, CO_2 monetization begins at $10 per ton in 2015 and escalates to $25 per ton (all in 2007 dollars) by 2025. After 2025, the cost of CO_2 is escalated at a rate of inflation of approximately 2.5 percent per year.

For the high CO_2 scenario, monetization also begins in 2015. However, the cost of CO_2 tracks the higher cost projections set out in the U.S. Department of Energy's (DOE) analysis of S. 2191 (the proposed Lieberman-Warner "America's Climate Security Act of 2007") scenarios (low international action).[4] Under this scenario, CO_2 monetization begins at $26.05 per ton in 2015 and escalates to approximately $42.45 per ton by 2025 and $69.44 per ton by 2035, the last year of the EGEAS study period (all in 2007 dollars).

In the high CO_2 scenario, it was also assumed that the cost of natural gas was 10 percent higher than in the base case. Two different models of the high CO_2 scenario were run, one in which EGEAS could pick future nuclear units and one in which new nuclear units were not an option. The high CO_2 cost scenario is the only one in which new nuclear units are an option. The high CO_2 model run where new nuclear units are available is less expensive on a total cost, net present value basis than the high CO_2 model run where new nuclear is excluded and is the model run included in Table 7.

Additionally, Commission staff assumed that several of the existing coal units will have emission control equipment installed within the SEA period (2007 through 2014). This was modeled by initially assuming the units will operate as they currently do (without emission control equipment). The units are then retired after the last year they are assumed to operate without the emission control equipment. The following year they are forced back into the model with the operating characteristics and costs of the original unit, with modifications to reflect the installation of the emission control equipment. The units staff assumed would install emission control equipment and the year of assumed installation for modeling in EGEAS are shown in Table A-4 in Appendix A. Table A-4 shows staff's assumption for the installation of emission control equipment. Some of these decisions still need to be reviewed by the Commission, and these assumptions should not be viewed as Commission determinations. Table 5 summarizes known information about possible emission control equipment construction in the future.

[4] Concurrent with the consideration of this SEA, Congress is considering a number of proposals aimed at reducing GHG emissions, including CO_2 reductions. One proposal introduced by Representatives Henry Waxman (D-CA) and Edward Markey (D-MA) would significantly overhaul climate and energy policy, including a cap and trade program that sets mandatory limits on GHG emissions over the next forty years. Future modeling assumptions will have to account for these more recent proposals. Of course, to the extent any climate proposal becomes law, these issues would cease to be modeling assumptions.

Table 5 Major Emission Control Projects* at Wisconsin Investor Owned Utilities' Power Plants

Unit Name	Utility Owner	Application Status	Type of Emission Control**
Pleasant Prairie 1	WE	Complete	SCR/FGD
Pleasant Prairie 2	WE	Complete	SCR/FGD
Oak Creek 5	WE	Complete	SCR/FGD
Oak Creek 6	WE	Complete	SCR/FGD
Oak Creek 7	WE	Complete	SCR/FGD
Oak Creek 8	WE	Complete	SCR/FGD
Columbia 1	WP&L/WPSC/MGE	Not Filed	FGD
Columbia 2	WP&L/WPSC/MGE	Not Filed	FGD
Edgewater 4	WP&L/WPSC	Not Filed	SCR (or SNCR)/FGD
Edgewater 5	WP&L/WE	Pending	SCR
Nelson Dewey 1	WP&L	Pending	FGD
Nelson Dewey 2	WP&L	Pending	FGD
Weston 3	WPSC	Pending	FGD

* Major emission control projects only include projects over $25 million. Table does not include combustion control projects for NO_X, and does not include activated carbon control projects for mercury.
** Selective catalytic reduction (SCR); flue gas desulfurization (FGD)

Unit Retirements and Conversions Assumed by Commission Staff

All of the coal units set out in Table 5 were assumed to continue operation through 2035. In all EGEAS modeling scenarios, Commission staff assumed the following units were retired in the year shown.

2008 – Oak Creek 9
2009 – Point Beach 5
2011 – Blount 3, 4 and 5
2012 – Pulliam 3 and 4, Blackhawk 3 and 4, Rock River 3, and Presque Isle 1 and 2
2013 – Rock River 4
2014 – Menasha 3 and Rock River 1
2015 – Rock River 2

Blount 6 and 7 are assumed to operate as coal units through 2010. They are then retired and forced back into the model in 2011 as 50 MW natural gas combustion turbines. Point Beach Nuclear Power Plant Units 1 and 2 have received a 20-year license extension by the Nuclear Regulatory Commission (NRC) in December of 2005 and are modeled as operating until 2030 (Unit 1) and 2033 (Unit 2). Kewaunee Nuclear Power Plant was assumed to be granted a 20-year license extension by NRC and operate to the benefit of Wisconsin through 2033.

Anticipated Growth Rates

Energy growth and demand are the variables in determining need for new generation. The Commission staff EGEAS analysis for the 2008 SEA examined the ATC peak and energy data for 2003 through 2006. The average energy growth for those years was approximately 1.0 percent per year. The peak growth was slightly more than energy. This energy use is net of demand-side management (DSM) savings. The energy needs for a specific utility will likely be different from the projected aggregate growth for the ATC footprint.

In the staff EGEAS analysis, energy use is assumed to increase at 1.0 percent per year. (In the data submitted by the utilities, the expected increase is approximately 1.8 percent per year.) Peak demand is assumed to increase at 1.5 percent per year from 2006 through 2025. As indicated earlier, the utilities' projection showed on a statewide basis growth of about 2.1 percent per year. From 2026 through 2035 peak demand is assumed by Commission staff to increase by 1.05 percent. These estimates are lower than estimated growth compiled from utility forecasts. While the Commission staff forecast used in EGEAS is based on recent historic usage in the ATC-footprint, higher than expected economic growth or the use of new technologies such as plug-in hybrid electric vehicles (PHEV) could result in an actual future growth rate closer to that forecast by the utilities. The load used by Commission staff for 2006 is 65,983.2 gigawatt hours (GWh). By the end of the SEA period (2014), the load is estimated to be 71,450.4 GWh using the growth percentages set out above. In response to comments on the draft SEA, staff reviewed historic ATC usage that included data from 2003 through 2008. The average annual growth rate in energy use over this period is less than the 1.0 percent assumed by staff in its EGEAS modeling, while the peak demand actually decreased from 2003 to 2008. As such, staff did not revise the energy and peak demand growth rates assumed in its EGEAS modeling.

If the actual energy and peak demand growth exceed that projected by Commission staff, the actual new plant needs may vary significantly from that reflected in Commission staff's EGEAS model results.

Future Estimated Fuel Prices

Just as energy growth is the largest variable to determine the need for new facilities, fuel prices are the largest variable in determining what the overall production cost will be. Higher fuel prices also make it more economical to install newer, more efficient units.

For Commission staff's EGEAS modeling in this final SEA, the cost of coal is estimated to be \$1.27 (in 2007 dollars) per million British thermal units (MBtu) and is escalated on an annual basis so that the annual cost of coal is the average of the estimates supplied by the utilities. The cost of natural gas is estimated to be \$9.27 (in 2007 dollars) per MBtu and is escalated on an annual basis so that the annual cost of gas is the average of the estimates supplied by the utilities. Fuel costs during 2008 have been dynamic, and volatile, rising mid-year and falling by year end.

Generation Options

The costs for generation technologies Commission staff used for EGEAS modeling purposes are shown in Table 6. The prices used for the assessment were based on a review of recently published cost estimates.[5] Construction costs for wind, natural gas, and coal electric generating facilities have increased substantially in recent years. Regardless of which type

[5] *Engineering News Record.* September 26, 2008.

of technology is selected, the total plan cost (in net present value (NPV) 2006 dollars) will be approximately $7 billion, 14 percent more than the same plan using construction costs from two years ago.

Table 6 Estimated Cost of Generation

Technology	Staff Estimated Capital Costs ($/kW)
Combustion Turbine (150 MW)	$766
Combined-Cycle (500 MW)	$964
Pulverized New Coal (500 MW)	$3,100
Wind (200 MW block)	$2,320
Nuclear	$6,500

For the Commission staff's EGEAS modeling, all capital costs were assumed to be capitalized and the costs were levelized or spread equally over the estimated life of the unit. The levelized interest costs were assumed to be 12 percent for all projects except coal which was assumed to be 12.2 percent. The model can also choose a 1-year power purchase option. Each power purchase option is 100 MW and up to four purchases can be made annually.

Nuclear

New nuclear power plants were not allowed as a planning option, except in one modeling run in the high CO_2 cost scenario. Current DOE projections put the opening of the Yucca Mountain repository in the years 2017-2021, which is beyond the current SEA period. Despite this, the NRC has received combined license applications for reactors in Alabama, Florida, Georgia, Louisiana, Maryland, Michigan, Mississippi, Missouri, New York, North Carolina, Pennsylvania, South Carolina, Texas, and Virginia. Nonetheless, in Wisconsin, unless the current state moratorium on new nuclear construction is lifted at the legislative level, nuclear generation is not an option given the current projected timing of the opening of the Yucca Mountain repository.

In the high CO_2 cost scenario, the new nuclear units were allowed beginning in 2020. Costs, timing of construction, and necessary regulatory approvals are all uncertain at this time. This is an issue that the Commission will continue to monitor.

Integrated Gasification Combined-Cycle

Integrated gasification combined-cycle (IGCC) plants are not a new plant option in Commission staff's EGEAS modeling. Currently, the capital cost of IGCC plants is approximately 10 percent more than a conventional pulverized coal plant. Further, without carbon sequestration, the emissions from an IGCC plant are not significantly less than for a conventional pulverized coal plant. Therefore, if EGEAS does not choose a conventional pulverized coal plant, it will not choose an IGCC plant.

Wind

As shown in Table 6, Commission staff assumed wind capital costs of $2,320 per kW in 2006 with a 2 percent annual escalation rate. The exact cost could be higher or lower. The federal production tax credit is assumed to be extended and is included in the price of all wind generation options included in the EGEAS model. Staff, in general, forced 400 MW of wind generation to be installed per year. This was adequate to meet the requirements of the 10 percent (by 2015) RPS in all modeling scenarios performed by staff, as well as the 25 percent renewable generation level by 2025 scenario. In certain years under the high CO_2-high natural gas cost scenario, up to 600 MW of wind is optimally chosen.

Wind was modeled as a non-dispatchable unit using hourly wind profiles. A 20 percent credit to the reserve margin was used for all wind generation. A sensitivity was run on the base scenario at 15 percent to the reserve. There was no change in the model results during the SEA period (2008 through 2014). It was assumed that utilities would install wind instead of obtaining fixed price contracts. As an option, the Commission may want to explore fixed price contracts regarding utility-owned wind generation in certain situations.

Demand Side Management

The high DSM EGEAS modeling scenario included an additional $100 million annually of expenditures for energy conservation, in addition to what was assumed in the base model. The DSM programs were modeled as limited energy units. This is consistent with how DSM programs have been modeled by some Wisconsin electric utilities in the past. This dollar amount came from a preliminary recommendation by the GWTF. The $100 million was allocated to the various DSM programs on a percentage basis equal to the percent to total of current DSM spending. The $100 million was assumed to be sufficient to acquire DSM at the current unit cost supplied by Wisconsin electric utilities.

The Renewable Portfolio Standard

Under Wis. Stat. § 196.378, the level of renewable resources should be approximately 10 percent of the energy requirement by 2015, on a statewide basis. This RPS requirement is modeled in all EGEAS scenarios modeled by Commission staff. In order to model this RPS requirement, staff has assumed that the RPS is met by wind generation. The amount of wind required is over 2,000 MW installed. If other sources of renewable energy are utilized, they are likely to be more expensive than wind, at least in the short term. Without the production tax credit, wind costs increase substantially.

The RPS standard does not require that the renewable generation facility be located in Wisconsin. In recent years, wind facilities supplying renewable power to Wisconsin electric utilities have been located in both Wisconsin and Iowa. The hourly wind profiles used by Commission staff in its EGEAS modeling reflect both Wisconsin and Iowa wind regimes.

Commission Staff EGEAS Scenarios

The transmission section of this final SEA discusses the Midwest Independent Transmission System Operator, Inc. (MISO) Transmission Expansion Plan (MTEP). MTEP08 contained four scenarios: the base scenario; a carbon monetization scenario; a 20 percent renewable scenario; and a limited supply of natural gas scenario. It is anticipated that MTEP09 will include additional scenarios such as a 30 percent renewable scenario and a regulation scenario in which only clean coal[6] is allowed to be added after 2013.

Commission staff modeled EGEAS scenarios with the intent that they approximately mirror the MTEP scenarios. Staff's EGEAS scenarios include a base scenario (including CO_2 monetization), a high CO_2-high natural gas cost scenario, a 25 percent renewable scenario, a high DSM scenario, and a high (plus 10 percent) and low (minus 10 percent) fossil fuel cost scenario (instead of a limited supply of natural gas scenario). Table 7 sets out the results of these modeling scenarios. The plan cost is the net present value cost for the entire plan (2006-2035), including extension period.

Table 7 Summary of Modeling Results

	Base Model		25% Renewable Model		High CO_2-High Natural Gas Cost Model	
Year	Plants Suggested by EGEAS Modeling *	Total Cost of Base Model **	Plants Suggested by EGEAS Modeling *	Cost Above Base Model **	Plants Suggested by EGEAS Modeling *	Cost Above Base Model **
2008	Wind (1)	$66.2 billion	Wind (1)	$1.7 billion	Wind (1)	$27.2 billion
2009	Wind (2)		Wind (2)		Wind (2)	
2010	Wind (2)		Wind (2)		Wind (2)	
2011	Wind (2)		Wind (2)		Wind (2)	
2012			Wind (1)			
2013			Wind (1)		Wind (3)	
2014			Wind (1)		Wind (3)	
2015	CT (1), Purchase*** (1)		Wind (1), CT (1)		Wind (3)	
2016	CT (1), Purchase (2)		Wind (2), Purchase (2)		Purchase (3)	
2017	CC (1)		Wind (2), Purchase (2), CT (1)		Purchase (5)	
	High DSM Model		**High Fuel Cost Model**		**Low Fuel Cost Model**	
Year	Plants Suggested by EGEAS Modeling *	Cost Above Base Model **	Plants Suggested by EGEAS Modeling *	Cost Above Base Model **	Plants Suggested by EGEAS Modeling *	Cost Above Base Model **
2008	Wind (1)	$-800 million	Wind (1)	$2.3 billion	Wind (1)	$-1.9 billion
2009	Wind (2)		Wind (2)		Wind (2)	
2010	Wind (2)		Wind (2)		Wind (2)	
2011	Wind (2)		Wind (2)		Wind (2)	
2012						
2013						
2014			Wind (2)			
2015	Wind (2)		Wind (2), Purchase (2)		CT (1), Wind (2), Purchase (1)	
2016			CC (1)		CT (1), Purchase (2)	
2017			Purchase (2)		CC (1)	

* ( ) indicates number of units installed
** Total plan (2006-2035) dollars (NPV 2006)
*** 1 Purchase = 100 MW

In the above Table 7, the total system NPV cost difference between the base model using a 10 percent RPS requirement and the sensitivity modeling using a 25 percent RPS requirement is stated as $1.7 billion. Additional discussion of how this number was calculated and its potential on end-user electric rates is necessary.

The additional cost of implementing a 25 percent RPS requirement shown in Table 7 is based on moving to such a future from a near-term base model that includes a 10 percent RPS requirement and CO_2 monetization. In moving to the 25 percent RPS requirement future, some of the cost of the additional renewable energy is offset by the cost associated with the displaced CO_2 emissions.

[6] Clean Coal means coal combustion technologies that allow the burning of coal with reduced air emissions.

While the base model includes likely near-term assumptions such as CO_2 monetization, this is not the present situation on which current electric rates are based. Moving to a 25 percent RPS requirement future will likely impact current electric rates significantly more than the $1.7 billion shown in Table 7, as the cost of implementing CO_2 monetization must also be included. The EGEAS modeling performed by Commission staff suggests that moving from the present situation of a 10 percent RPS requirement and no CO_2 monetization to the near-term base model (10 percent RPS requirement and CO_2 monetization) could add several billion dollars to the total system NPV cost. The exact impact on current rates from the monetization of CO_2 could vary significantly and depends on how the CO_2 allowances are distributed, *i.e.* how many allowances are purchased versus how many are allocated. The $1.7 billion cost of implementing a 25 percent RPS requirement is in addition to this.

Generation Planning Conclusion

Assuming all currently authorized generation is constructed and placed into operation, and electric utilities continue to construct renewable generation in order to meet the requirements of Wis. Stat. § 196.378, Commission staff's EGEAS analysis shows no additional generation for the state as a whole (beyond the renewable generating facilities) is needed in the SEA period (2007-2014). However, the EGEAS modeling results suggest that in the years immediately following the SEA period, additional natural gas electric generating facilities may be needed. This result occurs because the optimization is done on an ATC-footprint basis. Optimization on a specific utility basis could show different results. This is a very important distinction with significant policy implications, because applications for new generation plants that the Commission reviews during construction cases are usually made by an individual utility.

The high CO_2 cost scenario modeled in this SEA is based on climate bills introduced in past sessions of Congress. The impact of CO_2 legislation on the EGEAS modeling assumptions will be incorporated in future SEAs in order to provide as thorough a picture as possible of the impact of CO_2 monetization on Wisconsin utilities and ratepayers.

The escalating costs of all electric generation construction leads to the possibility that increased DSM may result in a lower-cost generation plan, depending on the unit cost of DSM. If the cost of additional transmission facilities is considered, the potential for cost-effective DSM options increases. Wind generation, and possibly biomass, will be constructed to comply with RPS standards. Commission staff has modeled only wind in meeting the RPS, as biomass is more costly at this time. The excess energy could be sold into the MISO market and, at a minimum, will give Wisconsin more flexibility with possible power plant retirements.

Transmission System Plans, Issues, and Developments

LOCATIONS AND DESCRIPTIONS OF PROPOSED TRANSMISSION PROJECTS IN WISCONSIN

By state statute, this SEA is to report all transmission lines designed to operate at voltages above 100 kV on which transmission providers propose to begin construction before 2014, subject to Commission approval. The transmission owners that provided transmission project information include ATC, DPC, and Xcel. "Construction" means building new lines, rebuilding existing lines, or upgrading existing lines. Building new lines requires new transmission structures and, likely, requires new right-of-way (ROW). Rebuilding or upgrading existing lines may also require new structures or new ROW.

To rebuild a line means to modify or replace an existing line; in other words, to keep it at the same voltage and improve its capacity to carry power through new hardware or design. To upgrade an electric line means to modify or replace an existing line, but at a higher voltage. An upgrade also improves the line's capacity to carry power. Both rebuilding and upgrading may require some (or many) new, taller structures. New ROW may also be needed if the new structures require a wider ROW, or if the line route requires relocation to reduce environmental impacts. Either way, rebuilt or upgraded transmission lines usually need significantly less new ROW than new lines.

The primary reasons for needing additional transmission lines may include one or more of the following:

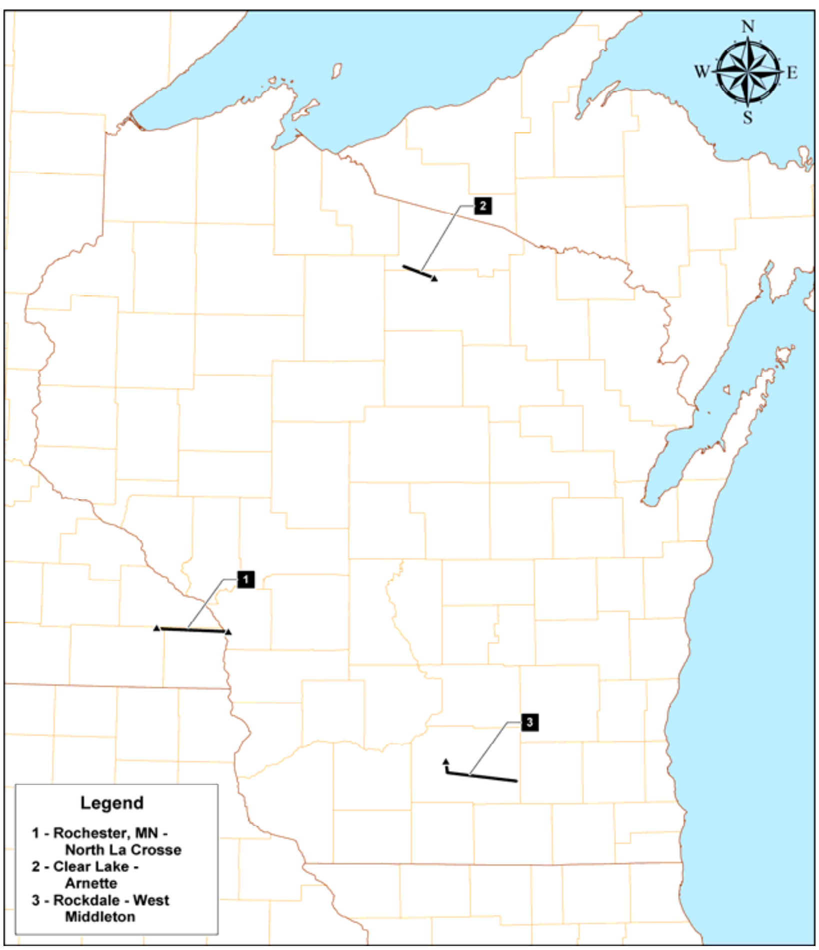
- Growth in an area's electricity use, which often requires new distribution substations and new lines to connect them to the existing transmission system, or needed increased capacity of existing transmission lines;
- Aging of existing facilities that has resulted in reduced reliability due to poor condition;
- Maintenance of system operational security for the loss of any one transmission or generation element;
- Increased power transfer capability or access;
- Generation interconnection agreements and transmission service requirements for proposed (or approved) new power plants;
- Maintenance of transmission system reliability and performance.

In general, the higher a line's voltage, the more power it can carry and losses are reduced. As a consequence, the higher-voltage transmission lines are important in delivering large amounts of power on a regional basis, and the lower-voltage lines primarily deliver power over a more limited area. The ability to deliver power reliably to local substations and the ability to import power from, or export to, other regions, are both important functions in providing adequate, reliable service to customers.

Table A-2 in Appendix A shows new electric transmission lines on which construction is expected to start by 2014 if approved by the Commission. Unlike the generation table, this table does not include any transmission lines already approved by the Commission and under some phase of construction; these would number about 20 projects.

Table A-3 in Appendix A lists proposed high-voltage transmission projects involving new ROW. This table provides further detail for only one proposed transmission line listed in Table A-2. Other lines in Table A-2 are proposed to primarily use existing electric transmission line ROW. Projects with Certificate of Public Convenience and Necessity (CPCN) applications already filed with the Commission are not listed in Table A-3.

Figure 5 Proposed High-Voltage Transmission Line Additions Involving New ROW, on which Construction is Expected to Start Prior to December 31, 2014, if approved by the Commission



TRANSMISSION PLANNING IN THE MIDWEST

Background

The Federal Energy Regulatory Commission (FERC) has asserted jurisdiction over operation of the transmission system in the U.S. because of its use in interstate commerce, and Congress has given FERC authority over transmission system reliability. FERC adopted Order No. 890 in February 2007 reforming the landmark 1996 open access rules in Order Nos. 888 and 889. See Appendix B for the nine planning principles of FERC Order No. 890. The expanded goals of the open-access transmission regulatory framework are to ensure transmission service is provided on a non-discriminatory, just and reasonable basis, as well as to provide for more effective regulation and transparency in the operation of the transmission grid. FERC's final rule on open access includes the following specific intents:

- Increase non-discriminating access to the grid by having consistency in the calculation of Available Transfer Capability methodologies in coordination with the North American Electric Reliability Corporation (NERC);
- Increase the ability of customers to have access to new generation resources by requiring open, transparent and coordinated transmission planning process;
- Increase efficient utilization of transmission by eliminating artificial barriers to the grid;
- Facilitate the use of the grid to obtain clean energy resources, such as wind;
- Strengthen the compliance and enforcement process.

In an important new development, FERC directed all transmission providers to develop a transmission planning process that satisfies nine principles of Order No. 890 and to clearly describe the transmission planning process in a new Attachment K to their Open Access Transmission Tariff. All Attachments K were filed by December 7, 2007. The transmission providers of interest in the Wisconsin area include: MISO, which is the regional grid operator in the upper Midwest spanning the approximate geographic area from Ohio in the east to Montana in the west and as far south as Missouri (see Figure A-3 for a map of RTOs); the Mid-Continent Area Power Pool (MAPP); Xcel; DPC; and ATC. FERC has conditionally accepted most Order No. 890 filings made by MISO, ATC, Xcel, and DPC.

Transmission planning is the most complex of the topics covered in this SEA. This is because transmission planning encompasses numerous overlapping issue areas, and requires the use of sophisticated computer modeling that factors in existing generation and transmission projects as well as new or proposed projects. Transmission planning has many economic, engineering, environmental, and political perspectives that must be considered, such as:

- Should the transmission planning focus on a particular utility, state, region, or sub-region, or the entire country?
- How should transmission planning factor in expected new generation developments?

- Should the transmission system be planned and constructed ahead of new generation developments, or should it lag those generation developments?
- Who should do the transmission planning?
- Should the transmission system be planned and constructed for reliability reasons and the elimination of system congestion, or should the transmission system be planned and constructed for a larger goal of fostering interstate commerce of electricity?
- Who should pay for any new proposed transmission projects? Should the costs be borne by the constructing utility alone, or shared on a regional or zonal basis?
- How can different state policies with respect to resource portfolios be factored in if one state, for instance, relies more on renewable resources than another state?
- How do projects that appear in transmission plans reach fruition? What process is used to approve the assorted projects, and who decides if the projects' costs are to be shared?
- How do policy makers ensure that the transmission system is neither underbuilt nor overbuilt?
- How does transmission planning factor in some states' preferences to more aggressively address environmental factors than other states?
- How does appropriate transmission planning factor in the varying types of providers for transmission service such as stand-alone transmission companies such as ATC and vertically-integrated utilities like Xcel?
- How does transmission planning accommodate the fact that some states have deregulated their electricity sectors more so than others?
- Can transmission system improvements and better generation dispatch in the region act as a substitute for new generation?
- How does increased use of energy efficiency and demand reduction programs affect the need for new transmission projects?
- How does transmission planning factor in new generation facilities when the exact location of this future construction is not known?

Due to this long list of questions and the difficulty in addressing all the issues simultaneously, no single preferred entity or transmission planning process has emerged. Rather, transmission planning is being conducted by different entities on different fronts and in different fashion. The following discussion highlights the forms transmission planning is taking in the area affecting Wisconsin. As part of this SEA, Commission staff has not produced an optimal transmission plan for Wisconsin.

MISO Transmission Planning

At present, MISO is using the following transmission planning principles:

- Make the benefits of a competitive energy market available to customers by providing access to the lowest possible electric energy costs;
- Provide a transmission infrastructure that safeguards local and regional reliability;

- Support local and federal renewable energy objectives by planning for access to all such resources such as wind, biomass, and DSM;
- Create a mechanism to ensure investment implementation occurs in a timely manner;
- Develop a transmission system scenario model and make it available to state and federal energy policy makers to provided context and inform the choices they face.

MISO hypothesizes that the current transmission planning paradigm, based primarily on reliability assessment which minimizes transmission build, leaves value for customers on the table. That is, the answers to the above questions require the total evaluation of all benefits including economic, reliability, and public policy concerns to meet longer-term needs for the next 20 years.

MISO Planning Cycle Approaches

MISO presently uses the following planning cycles when performing transmission system planning whether for a utility, the region of its footprint, or an even larger area beyond its footprint:

- 12-Month
    - Based on five-year NERC Reliability Standards (due to ten-year screens, the focus is on 2013 and 2018 this year).

- Multi-year
    - 10- to 20-year Economic View, which is value-based, including a Joint Coordinated System Plan (JCSP) with surrounding regional transmission providers such as Southwest Power Pool, Tennessee Valley Authority, PJM, New York ISO, and ISO New England.

- 12- to 24-Month
    - Targeted studies to address specific issues such as, congestion, narrowly congested areas, narrowly constrained areas, renewable portfolio standards in the Midwest, as well as queue related and operational studies. One example is the Regional Generation Outlet Study.

- MTEP
    - Annual – Each MTEP is a snapshot of currently recommended expansions resulting from all completed planning studies. MTEP also provides information for conceptually planned additions and other exploratory studies.
    - Projects approved in MTEP, depending on the project, may be eligible for cost sharing. That is, a transmission capital project’s cost may be borne by utilities outside the zone where the line is being constructed. MISO approved MTEP08 in December 2008.

MISO Transmission Planning Examples

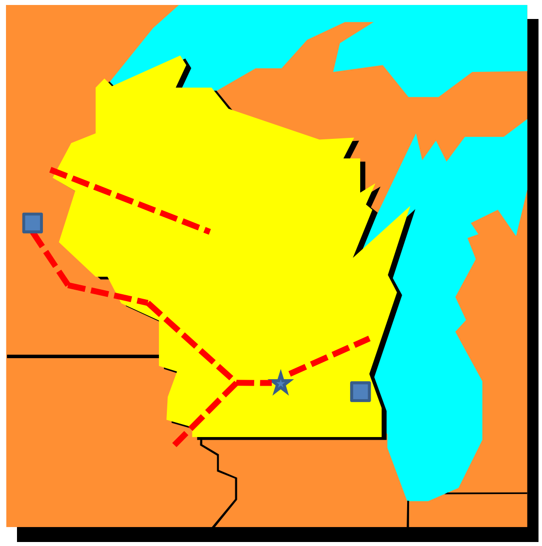
The MISO planning process relies on future scenario analysis that tests the ability of a particular set of transmission elements to provide a reliable system, in a timely manner, with different, possible futures. Reliability is composed of two components: security—the ability to not fail often; and adequacy—the ability to provide service constantly. MISO believes its scenario-based overlay planning architecture is a strategic long-term analysis that factors in the numerous concerns outlined in the questions above.

There are several future scenarios being considered by MISO. Possible sets of transmission lines were placed into load flow and production cost models to test performance for reliability and economics for each of those individual scenarios. Figure A-1 in Appendix A is the Universal Legend for transmission lines and generation. Figure A-2 in Appendix A is the base MISO Centric perspective for the complete MISO footprint as well as the eastern region of PJM, the RTO serving the area of Chicago, Delaware, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, and West Virginia. It is a complex diagram containing many potential transmission facilities as well as generation projects.

Figure 6 shows the MISO Centric Perspective from a Wisconsin perspective. This base MISO Centric perspective suggests that a Y-shaped 345 kV high voltage line may be needed in southwestern Wisconsin. One spur would come from the area near La Crosse to Spring Green; another spur would come from northeastern Iowa to Spring Green; and the last connector would be from Spring Green to West Middleton in Dane County. MISO also indicates another potential 345 kV segment in northwestern Wisconsin, and possibly one from the Madison area to an area north of Milwaukee. The lines on these charts are stylized representations of transmission projects that may be needed for reliability, access to renewable resources (such as wind to the west), adequacy, or economic commerce. The broken lines are conceptual. No utility has indicated to the Commission that it has plans to construct any of the facilities in Figure 6. MISO itself cannot build the transmission lines, as that is beyond its charter.

MISO has also explored transmission planning beyond its footprint. This is an area of ongoing significant controversial study and transmission planning. Usable results from these efforts, notably the JCSP, are not expected to be released until mid-2009.

Figure 6 MISO Centric Base 345 kV Transmission Plan for Wisconsin



From the Wisconsin perspective, there are currently several controversies surrounding MISO's transmission planning. Some of these controversial questions are:

- Should MISO plan for its entire footprint?
- Should MISO be able to dictate to any state that its transmission plan must be the plan put in place?
- Should MISO perform transmission planning using a top-down approach, or rather use an approach that builds on the plans and perspectives developed by individual stakeholders?
- Should regional and sub-regional planning be further explored to ensure Wisconsin's needs are met at the lowest cost?
- Should further study and analysis on the Y-shaped connector project be done?
- Does MISO's planning approach sufficiently factor in local public and stakeholder input?
- Should MISO work with others outside of the MISO footprint to consider the electricity needs for the entire eastern interconnection?
- How should generation planning be considered in MISO's transmission planning?

In summary, MISO's transmission planning can be a very useful tool to advance the debate on the requisite transmission system needed to accommodate numerous objectives, but MISO's approach must not be viewed as the sole determining method.

ATC Transmission Planning Activities

ATC is the largest transmission provider in Wisconsin. The creation of ATC was contemplated in the late 1990s, as a result of federal and state policies and orders, including passage of 1999 Wisconsin Act 9. ATC, a stand-alone transmission company, was created in 2001. ATC's footprint also includes Michigan's Upper Peninsula. Details regarding potential ATC transmission construction projects can be found in Tables A-2 and A-3, and Figure 5.

ATC has identified the following detailed transmission planning processes that it uses:

Network Adequacy Planning

The planning process that encompasses the largest share of ATC projects is Network Adequacy Planning. This process is an overall assessment of the ATC system and its ability to handle growth in electricity consumption, and deliver power under changing system conditions in the future. ATC simulates future conditions, examines weaknesses and models a variety of potential solutions using its publicly posted planning criteria.

Economic Project Planning

Economic Project Planning refers to studies that look for transmission system congestion that has a significant adverse impact on the delivered cost of energy to consumers. ATC uses historical data and future power flow forecasts in models to help identify potential ways to mitigate or relieve those effects.

Distribution to Transmission (D-T) Interconnection Planning

D-T Interconnection Planning examines ways the transmission system may need to expand or interconnect new electric substations that are proposed to support local growth. When business or housing developments are built in areas that previously were rural, the electric system must be expanded to supply new power needs. When local utilities' expansion plans require new interconnections with the transmission system, utilities must submit a load interconnection request form. ATC's load interconnection business practice outlines how they work with utilities to develop the most cost-effective solution and maintain an interconnection queue to help facilitate communication with utilities about these requests.

Transmission to Transmission (T-T) Interconnection Planning

T-T Interconnection Planning examines the impact on the system of transmission expansions outside of and adjacent to ATC's service area. ATC coordinates their assessments of the need for new facilities with the plans for adjacent transmission systems to identify a wider variety of options on a cooperative basis.

Generator to Transmission (G-T) Interconnection Planning

G-T Interconnections Planning studies the impacts that additions or changes in electrical generation outputs have on the transmission system. These impacts often require modifications or expansions of transmission facilities. Requests for interconnection studies of the transmission system must be sent to MISO. ATC works collaboratively with MISO on these studies and also offers supplemental interconnection guidelines for generators wishing to connect new facilities to the ATC transmission system.

Transmission Service Planning

Transmission Service Planning refers to transmission system studies that are required to resolve future delivery issues. A utility's purchase of power request is made to MISO. MISO and ATC determine if there is adequate "available transmission capacity" to accommodate the power purchase. If not, then the studies recommend solutions to deliver the power as requested.

From a Wisconsin perspective, the ATC approach has been used on several approved projects, and is being tested again on a major proposed project in Dane County, the West Middleton to Rockdale project. The advantage of the ATC method is that it is a detailed bottoms-up form of transmission planning with significant input from Wisconsin stakeholders. Some parties question whether ATC's transmission plans properly synchronize the requirements of a regional transmission grid in the Midwest, and whether ATC may be proposing projects that focus more on increasing the company's size and rate base. To deal with this concern, ATC transmission projects and costs are carefully scrutinized and evaluated by the Commission during appropriate construction application dockets. FERC Order 890 requires ATC to meet the requirements of MISO and other regional RTOs.

Xcel and Dairyland Power Cooperative Planning Activities

Xcel and DPC also provide transmission service on the western and in the northern-western portions of the state. The Xcel footprint also covers eight states from Minnesota and the Dakotas to Colorado and New Mexico. The DPC footprint also includes Minnesota, Iowa, and Illinois.

Xcel and DPC are members of MAPP. MAPP has approximately 43,000 MW of generation and over 21,000 miles of transmission lines. The summer peak is approximately 34,000 MW. The transmission group has approximately a dozen transmission owners and 40 transmission user members. On behalf of its members, MAPP filed an Attachment K with FERC which describes the comprehensive transmission planning process it will be using. Individual members have also supplied additional information on particular local planning processes. The near term transmission construction plans of Xcel and DPC can be found in Tables A-2 and A-3. A major project that is expected is a transmission facility linking the Minneapolis-St. Paul area to Rochester, Minnesota, and then crossing into Wisconsin near the north La Crosse area. The Commission expects a construction application on the crossing of the Mississippi River in 2009. Partners proposing this line indicate that the 345 kV facility would foster greater transmission system reliability.

Integrated Generation and Transmission Planning

The above discussion highlights the extremely complicated nature of transmission planning and perhaps requires a new interpretation, allowing all entities to engage in or perform transmission planning within certain confines and with certain understandings. This 2008-2014 final SEA allows for comments on the above planning processes considering the multiple aspects of Wisconsin, MISO, and approaches in other MISO states such as those in MAPP.

As long as EHV projects are not dictated to Wisconsin, one may view the various transmission grid designs not as the *plan* but as an ongoing *strategic analysis*, requiring the ongoing use of an informed *stakeholder process* considering all the multiple dimensions and questions outlined earlier. In other words, transmission planning takes on the form of a dialogue, but that dialogue must be in all directions.

For the Commission, strategic analysis is not focused on a specific generation or transmission planning outcome or optimized map of assorted projects, but on a vetting of many potential generation construction and transmission grid possibilities. Using a financial analogy, the Commission must construct a portfolio of transmission investments in conjunction with neighboring states that is robust enough to last through numerous uncertainties facing the nation, while continuing to match the risk tolerance of the owner(s) and the customers' ability to pay along the way.

Recently, an important new transmission planning exercise commenced that could form the basis of that strategic analysis or dialogue. ATC, as a part of its ten-year plan, is continuing to look at economic transmission planning for its footprint. ATC held an initial stakeholder meeting in February 2008 in which sub-regional transmission planning was discussed with stakeholders, including neighboring transmission owners. Subsequent meetings were held in June 2008. The meetings summarized historical congestion locations, causes, and severity. To find economic solutions, a series of future scenarios are being modeled for analysis. These include:

1. Robust economy
2. High retirements (older coal)
3. Environmental ($25/ton CO_2)
4. Slow growth
5. Potential DOE wind mandate
6. Regulatory limitations

ATC has been collecting preliminary comments and it will post preliminary results and collect further comments on this sub-regional planning in the near future. ATC will also compile a project list and associated assumptions. There is expected to be additional analysis and interaction with stakeholders. In September 2008, ATC posted its latest ten-year plan. In December 2008, the long range potential economic projects were posted. Analysis is continuing. The final projects then will move through the regulatory process. The sub-regional approach addresses the earlier cited concern that an ATC-only approach does not properly synchronize with neighboring systems.

Transmission Planning Summary

ATC, Xcel, DPC, MISO, *et al.*, are doing transmission planning under FERC Order No. 890. The key is to make sure that Wisconsin interests are protected. These interests include low costs to ratepayers, as well as preserving state's rights issues. The Commission emphasizes that states should have a significant role in deciding what projects should be built in their states. The joint effort by ATC, Xcel, DPC, *et al.*, is a good start to developing a regionally beneficial plan for Wisconsin. Because the Commission must be involved in planning does not mean that the Commission endorses or approves any specific plan or the projects in that plan. Individual projects must receive scrutiny by the Commission in appropriate construction dockets as prescribed by state law. The Commission is involved in all of the transmission planning efforts mentioned in this report and recognizes the challenges in balancing regional planning and state authority.

The Commission will also be providing significant input to the numerous MISO transmission planning studies, either directly or through the Organization of MISO States.

The Commission's additional involvement in transmission discussions as part of the Upper Midwest Development Initiative, the Organization of MISO States, MISO's RECB Task Force, and the Midwest Governors Association insure a Wisconsin perspective in additional regional transmission planning efforts. The Commission is also cognizant of the potential for an increased federal role in transmission planning and siting, particularly as it relates to transmission for renewable energy development. Several proposals, including Senator Harry Reid's proposed "Clean Energy and Economic Development Act" (introduced as S. 539) and a proposal by Senator Jeff Bingaman (yet to be introduced) are being considered in the current Congress. These proposals seek to enhance federal authority and encourage, if not require, regional transmission planning efforts.

Market Analysis and Planning Reserve Margin Forecasts

This section provides an assessment of Wisconsin's electric industry as it addresses four concerns mandated by law. Wis. Stat. § 196.491(2)(a) specifically requires the SEA to assess: (1) the extent to which the regional bulk power market is contributing to the adequacy and reliability of the state's electrical supply; (2) the adequacy and reliability of purchased generation capacity and energy to serve the needs of the public; (3) the extent to which effective competition is contributing to a reliable, low-cost, and environmentally sound source of electricity for the public; and (4) whether sufficient electric capacity and energy will be available to the public at a reasonable price.

The following sections address the above concerns. The analysis incorporates data submitted by the electricity providers in their SEA submissions and other data collected by Commission staff.

AN ASSESSMENT OF THE EXTENT TO WHICH THE REGIONAL BULK POWER MARKET IS CONTRIBUTING TO THE ADEQUACY AND RELIABILITY OF THE STATE'S ELECTRIC SUPPLY

New natural gas-fired peaking and intermediate load generation, improvements to the intra-state transmission system, and additional experience with the regional energy market are significant changes that have occurred since the last SEA.

Looking forward, three new large coal-fired baseload facilities are expected to begin commercial operation between 2008 and 2010. One new large intermediate load natural-gas fired facility began commercial operation in 2008.

To comply with the Wisconsin renewable energy portfolio, wind generation in Wisconsin and in neighboring states either owned or under contract to Wisconsin utilities is expected to add additional intermittent generation capacity of several hundred MW between now and 2015.

As new generation capacity continues to be brought into service, the amount of capacity purchases through purchased power agreements is expected to drop significantly through 2014. As can be seen in Table 1, capacity purchases made on a system basis are expected to drop from 725 MW in 2006 to 622 MW in 2014. Yet reliability is expected to remain robust with a planning reserve margin forecast through 2012 above 17 percent. Planning reserve margins are often finalized through capacity purchases made a short time ahead of any shortfall. Wisconsin, even seven years into the future, has established planning reserve margins that are very robust this far ahead of need. The current estimate for seven years hence is nearly 12 percent.

The sale of the Point Beach Nuclear Power Plant from WEPCO to FPLE-Point Beach, a subsidiary of the Florida Power and Light holding company, completes the sale of Wisconsin's utility-owned nuclear power plants to organizations specializing in the ownership and operation of fleets of nuclear generation facilities. As part of the sale, WEPCO entered into a life-of-license renewal purchased power agreement, securing the energy production from the facility for the utility and its customers until the two nuclear units' current licenses expire in 2030 and 2033.

Also noted in Table 1, the MW capacity under contract from merchant power plants is expected to rise from 3,518 MW in 2007 to 4,088 MW in 2008. This increase is because of the sale of the Point Beach Nuclear Power Plant to FPLE-Point Beach from WEPCO after the summer 2007 peak. Even with the sale of the Kewaunee Nuclear Power Plant and the Point Beach Nuclear Power Plant, and the associated power purchase agreement by the former utility owners for the capacity and energy from the facilities, MW of capacity from merchant power plants drops from 4,083 in 2008 to 2,487 MW in 2013. 2013 is the last year of the power purchase agreements between WPSC and WP&L, the two previous utility owners of the Kewaunee Nuclear Power Plant and Dominion Energy Kewaunee, the current owner of Kewaunee. The drop in capacity under contract is directly linked to the expansion of utility-owned generation during this time frame. After 2013, changes in capacity under contract will depend, at least in part, on whether or not the power purchase agreements for capacity and energy from the Kewaunee Nuclear Power Plant are renewed.

Planning reserve margins were a major concern in the earliest SEAs. In the second half of the 1990s actual reserve margins fell to less than 10 percent four out of five years. The lowest actual reserve margin fell to 6.7 percent in 1995. By contrast, the actual reserve margin in 2006 was 20.4 percent and for 2007 was 19.1 percent. 2006 was a cool summer, but had one very intense heat wave at the end of July continuing into the first two days of August. At that time, MISO hit a peak demand that was not exceeded in 2007. The robust planning reserve margin in Wisconsin in 2006 provided an extra measure of reliability protection for Wisconsin utilities and their ratepayers. Current high reserve margins come at a cost and the Commission's recent lowering of the reserve margin requirements will help to balance cost with reliability.

Sufficient capacity remains only half of the story. Getting the power from the generation source to the load is the second half. Wisconsin's current transmission system has numerous constraints that limit the unfettered flow of electricity into and within the state. These numerous constraints led MISO to name the Wisconsin Upper Michigan System (WUMS) area of Wisconsin and Michigan as a narrowly constrained transmission area (NCA). For five years there are special protections available to Wisconsin and Michigan to avoid undue prices on electricity in the wholesale market. It is expected that the current and ongoing transmission system expansion and improvements will greatly enhance the ability to move electricity into and within Wisconsin by 2010 when the special protections will be withdrawn. MISO expects the NCA designation to be lifted from WUMS by 2011 based on planned and approved projects.

AN ASSESSMENT OF THE ADEQUACY AND RELIABILITY OF PURCHASED GENERATION CAPACITY AND ENERGY TO SERVE THE NEEDS OF THE PUBLIC

Purchased generation capacity and energy may occur from facilities located within Wisconsin or from facilities located outside of Wisconsin. For the moment, NSPW and SWP&L will be considered separately. These two utilities have Minnesota-based affiliates where much of their generation capacity and energy needs are met as though they were part of the affiliates' system. The Wisconsin utilities in the eastern portion of the state are not part of multi-state affiliate networks that dispatch electricity across multiple states as a system. These WUMS utilities were well-placed in the late 1980s and throughout the early to mid-1990s to make purchases of excess generation capacity and energy, especially from Illinois. This became more problematic as the transmission grid was opened up via open access under policy direction of FERC in 1996. Thus, much of the past discussion in the initial SEAs on purchased generation capacity and energy focused on imports of generation capacity and energy, specifically their availability in light of increasing transmission congestion.

Several things have changed in recent years with respect to purchased generation capacity and energy. The aforementioned sales of the Kewaunee Nuclear Power Plant and the Point Beach Nuclear Power Plant have significantly broadened the purchased power market to include baseload generation in addition to the combustion turbine and combined-cycle generation that has a much lower capacity factor. The combustion turbine market is usually a market that focuses on generation capacity that is only expected to be used around 5 to 10 percent of the time. Combined-cycle units have higher capacity costs but are much more efficient. For the higher capacity costs, but lower generation costs, these plants are expected to be used from between 25 percent of the time to perhaps even more than 70 percent of the time, depending upon fuel costs. A nuclear powered baseload plant has very high capacity costs, but very low cost of generation. For a nuclear power plant (and to a lesser extent a large coal-fired baseload plant) to be commercially viable, it needs to be used with capacity factors of at least 80 percent.

When comparing the market for purchased generation capacity in 2008 to the same market in 2000, more of the purchased generation capacity and energy will be from facilities in Wisconsin. While some independent power producer (IPP) combustion turbines have been purchased by Wisconsin utilities, the sale of the state's three nuclear units to groups specializing in the operation of nuclear power plants has resulted in far larger amounts of capacity and energy now being sourced by IPPs in Wisconsin. With the purchase of nuclear baseload energy, more GWh of total energy will be purchased than in the past.

The market for purchased generation capacity and energy continues to evolve. The Commission continues to watch developments at MISO and how generation capacity and energy markets continue to change.

In two specific cases, the Kewanuee and Point Beach power plant sales, the Commission found that issues, including reliability concerns, can be overcome to allow the sale of these particular rate base baseload plants with power purchase agreements that protect Wisconsin ratepayer interests.

AN ASSESSMENT OF THE EXTENT TO WHICH EFFECTIVE COMPETITION IS CONTRIBUTING TO A RELIABLE, LOW COST, AND ENVIRONMENTALLY SOUND SOURCE OF ELECTRICITY FOR THE PUBLIC

The issue of reliability has been addressed in the previous sections of this report. This section will deal with the low cost and environmentally sound provisions required by statute.

FERC has the authority under federal law to regulate the market for wholesale power. As part of FERC's regulatory responsibility, it established rules for regional transmission authorities and to allow those regional transmission authorities to establish markets for energy. This has culminated in the Day 2 market under MISO that sets day ahead and real time prices for energy on a location by location basis throughout the area served by utilities participating in MISO. All Wisconsin utilities are part of MISO.

Figures 7 and 8 show the on-peak LMP from April 1, 2005, through December 31, 2007, for four MISO price points—an Illinois hub price compared to a Wisconsin load node price, WEC.S, the price node for the southern Wisconsin load of WEPCO, and the Minnesota hub price compared to the price node for the Wisconsin load served by WPSC, WPS.WPSM. The WEC.S node is representative of LMPs set for southern Wisconsin. The WPS.WPSM node is representative of LMPs set for northern Wisconsin. The Minnesota hub price looks at prices to the west of Wisconsin and the Illinois hub price looks at prices to the south of Wisconsin. The west and the south are the two primary paths of imported power into Wisconsin.

At the inception of the MISO Day 2 market on April 1, 2005, both of the Wisconsin node prices were often out of step with prices to the west and to the south. This is an indication of transmission constraints that cause either congestion charges or loss charges to push the LMP prices apart. In MISO, the energy charge in the LMP is always the same for all areas. All LMP price differences can be attributed to differences in congestion and/or loss charges.

As new transmission links to the south (primarily the 345 kV connection between Wempletown and Paddock) and new generation within the state (primarily new natural gas-fired combined-cycle units) came on line, the WEC.S and Illinois hub LMPs converged. LMPs in northern Wisconsin, as represented by the WPS.WPSM node, continue to track more closely to the Minnesota hub. Because of persistent transmission concerns in Minnesota and Iowa, a portion of this area has now also been identified by MISO as a narrowly constrained area. The spring 2008 energizing of the remaining portion of the Arrowhead-Weston 345 kV line and the commercial operation of the new Weston 4 power plant should begin to relieve the congestion and loss issues in future years that are likely to be a root cause of the LMP deviation between southern and northern Wisconsin LMP nodes. In late 2009, when the Gardner Park-Central Wisconsin, Morgan-Werner West, and Werner West-Clintonville transmission projects are completed, there is likely to be additional relief on the congestion and loss charges driving differentials in the LMPs between southern and northern Wisconsin. Far western Wisconsin, which is closely identified with the narrowly constrained issues facing southeastern Minnesota and northeastern Iowa, is likely to need other transmission system improvements to more closely align Minnesota hub prices with LMP prices in the rest of MISO.

Figure 7 Average Hourly Day-Ahead LMP for WEC.S and Ill.Hub

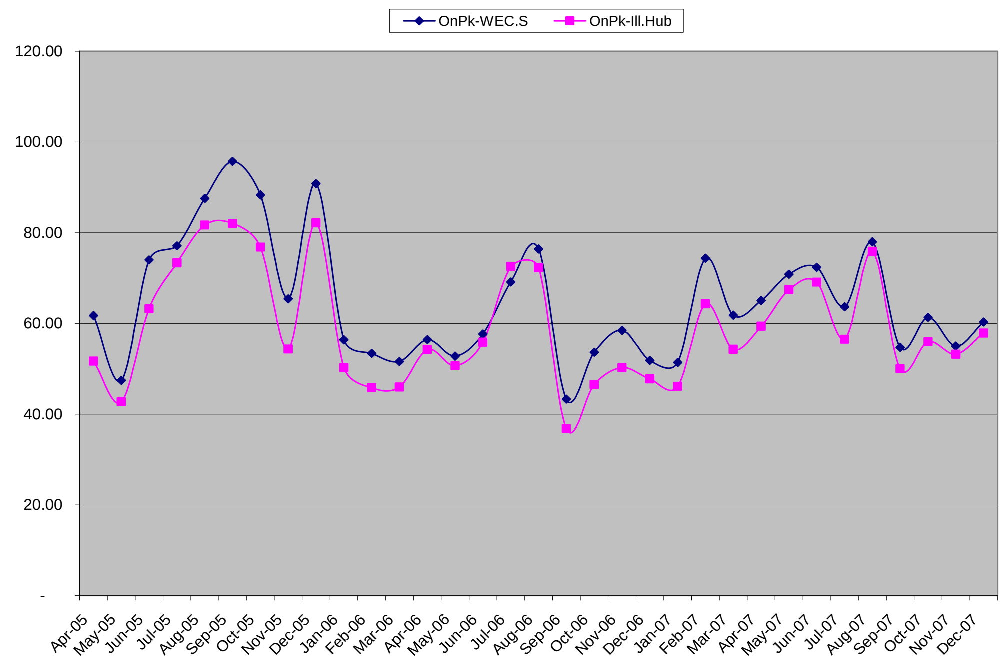
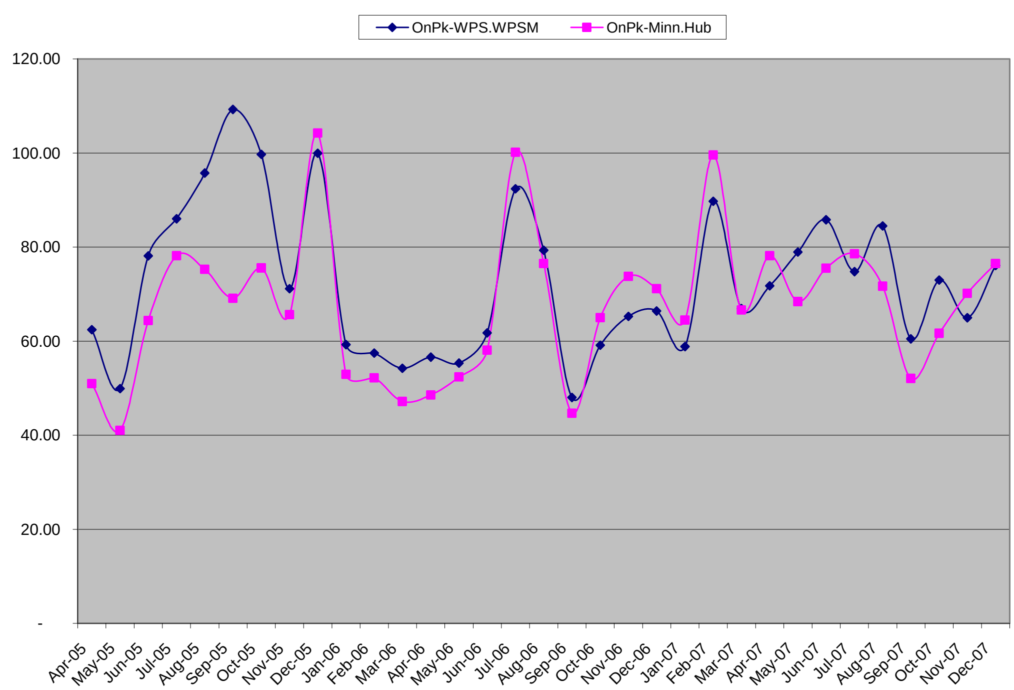


Figure 8 Average Hourly Day-Ahead LMP for WPS.WPSM and Minn.Hub



The final topic in this section is an assessment of the third statutory requirement—whether competitive markets are contributing to an environmentally sound source of electricity for the public. According to conventional economic theory, competitive markets will consider all direct economic costs as well as any indirect costs associated with externalities, such as pollutants, as long as the externalities in question have been regulated by either command and control methods or by some form of monetization in the form of taxes or emissions allowance trading, for instance. In cases where legitimate externalities have not been so factored in, the competitive marketplace will ordinarily ignore any of the non-private costs associated with such externalities. There may be some exceptions in cases where the public may be willing to pay a premium for goods or services with a better environmental footprint. In Wisconsin, such an example might be individual utilities offering up their green pricing programs whereby customers may buy wind power.

FERC has regulatory authority over MISO. MISO dispatches generation and transmission assets to facilitate wholesale competition in the interstate electric power market. The Commission remains vigilant in monitoring the MISO tariff with FERC and in participating directly with MISO and with our sister states to assure that the MISO is obtaining the promised benefits of lowering the cost of wholesale electricity. The Commission remains concerned that while the MISO is obtaining benefits in lowering electric production prices it is not clear that the regulatory and administrative costs associated with securing lower prices are significantly greater than the benefits of lower wholesale electric prices.

With this background, competitive power markets have been contributing to an environmentally sound source in the cases of pollutants and externalities that are under public policy supervision. Examples would include SO_2, NO_x, particulate pollution, and mercury. On the other hand, competitive power markets may not be contributing to an environmentally sound source in the cases of pollutants and legitimate externalities that are not under appropriate or adequate public policy supervision. Examples might include mercury deposition, permanent nuclear waste disposal, and greenhouse gases.

Commission staff worked with the GWTF to assist the GWTF and its working groups in gathering and analyzing the data needed to develop sound policy recommendations as Wisconsin, the nation, and the world begin to address the most significant environmental issue of our time. The Commission also continues to assist the Department of Natural Resources (DNR) with technical support as DNR works to implement the governor's goal of reducing mercury emissions from coal-fired power plants by 90 percent.

The Commission will continue to work on the myriad of issues associated with balancing environmental protection with reliable and affordable electric energy.

PSC PERSPECTIVE ON FERC ORDER 719

In 2008, FERC issued Order 719 to revamp certain issues with respect to RTOs. MISO is the RTO that covers the area affecting Wisconsin. In April 2009, MISO needs to make a compliance filing to FERC addressing market monitoring, demand response, RTO responsiveness, and long-term contracting. The Commission is working through the Organization of MISO States (OMS) to make sure MISO has the view of this state and the other states prior to MISO making its compliance filing. At present this involves commenting to MISO through its stakeholder processes.

In two key Order 719 areas, the Commission has expressed reservations with market monitoring and prospective market power mitigation being put into the hands of RTO management, which FERC now requires. Prior to Order 719, market power mitigation was in the hands of the independent market monitor. The PSC and the Ohio Public Utilities Commission have asked FERC to reconsider this part of its Order 719.

FERC Order 719 allows a new category of wholesale market participants known as Aggregators of Retail Customers (ARC). ARCs provide demand response services to groups of retail customers and bid these demand reductions into wholesale markets. Order 719 establishes an ARC's right to participate directly in wholesale markets, unless their activity within a particular state is prohibited by state law. The Commission is participating in the implementation of this provision through the Midwest ISO Demand Response Task Force and is also considering the issue in a separate generic docket. While ARCs could bring new technologies and economies of scale to the provision of demand response service, allowing ARCs into Wisconsin's regulatory regime may pose some problems. For example, ARCs could interfere with existing demand response programs and may have unintended detrimental financial consequences for non-participating customers. There are also uncertainties about the legal status of ARCs under Wisconsin law, including the application of consumer protection rules that govern electric utilities and electric utility customers. Finally, there are concerns about the determination of the appropriate compensation that should be paid to ARCs for load reductions and the sources of that compensation.

AN ASSESSMENT OF WHETHER SUFFICIENT ELECTRIC CAPACITY AND ENERGY WILL BE AVAILABLE TO THE PUBLIC AT A REASONABLE PRICE

The previous SEA spent some time discussing this topic. As noted previously, the Commission has approved CPCNs for three new large coal-fired baseload generation units. The Commission has also approved CPCNs for new combined-cycle natural gas generation, wind generation, and combustion turbine natural gas generation. As noted in Table 1, planning reserve margins are projected to be above, or very close to, 18 percent through 2012. Both the magnitude and the mix of new electric generation appear to answer the statutory concern about sufficient capacity in the affirmative. Wisconsin's electric generation future is in much better shape now than it has been in the past with respect to capacity and energy.

Several issues regarding the capacity and energy infrastructure remain.

Wisconsin still has as part of its generation fleet several very old, small coal-fired boilers. These units tend to have low levels of efficiency and tend to be much harder to control to meet pollution reduction requirements. The federal courts have vacated both the U.S. Environmental Protection Agency's (EPA) Clean Air Mercury Rule (CAMR) and Clean Air

Interstate Rule (CAIR). DNR has adopted a state-specific mercury rule that creates a multiple-year plan to achieve the governor's goal of a 90 percent reduction in mercury emissions. The legislature has completed its review process and the mercury rule is now in effect. The adopted rule not only has a workable time line for installing equipment at the largest mercury emitting electric generating facilities in Wisconsin, it also recognizes the inherent difficulties in achieving mercury controls at the smaller electric generating facilities and provides for specific mercury control reviews for these units that will include a review of the economic consequences of achieving mercury reductions at these smaller facilities.

The vacature of the EPA's CAIR package is unlikely to absolve any electric generation facilities in Wisconsin from future emission reduction obligations. The multi-pollutant option in the Wisconsin mercury rule may provide a path for utilities to install pollution control equipment that is likely to be needed in a manner that maintains affordable and reliable electric energy for Wisconsin. The PSC will continue to take note of the likely next steps in NO_x, SO_2, and mercury emission controls, and will be ready to provide technical assistance to DNR and report to the legislature on these issues as requested.

The state has implemented a renewable energy portfolio requirement. Currently wind generation is the lowest cost renewable energy option. Renewable energy portfolio requirements will affect Wisconsin's optimal energy expansion path. CPCNs for multiple wind farms have been approved by the Commission and are under construction. Additional applications for wind farms have been received by the Commission or are expected very soon. Several of the new applications are for wind farm development outside of Wisconsin. Areas in Iowa and Minnesota have much more favorable wind profiles than can be found in Wisconsin and these sites have been increasingly attractive to wind farm developers. Wisconsin, in 2008, has a significant fleet of combustion turbines and combined-cycle units. These units are critical to a generation fleet with significant wind capacity. Wind, while having very low marginal costs of generation, has unpredictable availability. To complement the low and unpredictable availability factor for wind, there needs to be rapidly available alternative generation capacity. Natural gas-fired combustion turbines and combined-cycle units can fill this need. This may imply higher capacity utilization for combustion turbines and combined-cycle units. This raises a concern as Wisconsin does have a number of older combustion turbines, some running on fuel oil. It has been economic to hold onto these units given their relatively low capacity utilization. However, if wind resources are expanded either in Wisconsin or outside of Wisconsin for use in Wisconsin, some combustion turbines may need to be replaced with newer, more reliable and less polluting units. With any generation planning scenario, Wisconsin's geography must be taken into consideration, *i.e.* geographic limitations like the Great Lakes.

It is possible that the renewable portfolio requirements will delay the need for both new baseload facilities and new peaking facilities. Although there are limitations created with variable generation in planning efforts, it is possible to mitigate some of the variation. It is paramount that integrating wind into generation portfolios be accomplished.

The capital costs of all forms of electric generation capacity have increased substantially since the last SEA. Over the past two years construction costs have increased, driven by tight markets for skilled labor, rapidly rising prices of critical construction materials including copper, steel, and cement, escalation in energy prices that feed into the higher cost of construction materials, and increased demand for critical generation components such as turbines and transformers fueled by rapidly growing economies such as China and India. The capital cost of new capacity has, perhaps, more than doubled in the past two years. This will inevitably lead to rate increases.

At the same time, the rate of growth in the amount of energy consumed and the growth in peak demand have tempered the need for new capacity, especially peaking capacity. The Commission will continue to carefully weigh the need for new capacity, as well as the optimal generation mix, as we move forward.

Rates

It should be noted that direct rate comparisons are becoming less meaningful as states are at different points in the construction of new power plants and some states have deferred rate increases to commence in years after 2009. For instance, in the Midwest there are many regulatory rate structures in place. Among the existing regulatory rate structures, there are states with vertically integrated utilities and states with stand-alone transmission companies, like Wisconsin. Fuel cost treatment varies from state to state, as well as treatment for deferrals of many different costs. In some states, rate reductions and freezes enacted by the legislature are soon to expire; some have already expired. The good news is that Wisconsin is ahead of other states with respect to the construction cycle of new electric generation and transmission facilities needed to address future service reliability.

According to the Energy Information Administration's (EIA) reported rate information in its Electric Power Monthly–March 2008 report, Wisconsin's 2007 electricity rates for residential customers—10.72 cents/kWh—were higher than the Midwest average of 9.40/kWh and very close to the national average of 10.65/kWh. Commercial rates in Wisconsin for 2007—8.64/kWh—are lower than the national average of 9.68/kWh. Industrial rates—6.18/kWh—were higher than the Midwest average of 5.65/kWh, but lower than the national average of 6.38/kWh. Fuel prices and purchased power cost increases, as well as construction costs for generation and transmission facilities, are the significant drivers of recent rate increases. Rate increases can be mitigated somewhat with energy conservation, innovative utility financing related to environmental trust fund programs, and other new rate options.

Changes in the ownership of electric generation, future transmission facilities, construction and timing of new utility generation plants, changing fuel costs, and the emergence of the MISO Day 2 and Day 3 Markets for power and ancillary services can have a significant impact on the rates Wisconsin customers pay, as well as how Wisconsin rates compare to other states' electricity rates.

Tables 8, 9, and 10 summarize average rates for residential, commercial, and industrial rates in the Midwest and the country.

Table 8 Residential Average Rates in the Midwest and U.S. (in cents)

	2000	2001	2002	2003	2004	2005	2006	2007
Illinois	8.83	8.70	8.40	8.38	8.37	8.34	8.56	10.33
Indiana	6.87	6.90	6.90	7.04	7.30	7.49	8.25	8.06
Iowa	8.37	8.40	8.30	8.57	8.96	9.36	9.77	9.41
Michigan	8.53	8.40	8.50	8.35	8.33	8.60	9.81	10.34
Minnesota	7.52	7.60	7.50	7.65	7.92	8.34	8.74	9.02
Missouri	7.04	7.00	7.10	6.96	6.97	7.08	7.62	7.72
Ohio	8.61	8.30	8.10	8.27	8.45	8.50	9.45	9.59
Wisconsin	7.53	7.90	8.10	8.67	9.07	9.64	10.50	10.72
Midwest Average	**7.97**	**7.90**	**7.83**	**7.89**	**8.17**	**8.42**	**9.09**	**9.40**
U.S. Average	**8.21**	**8.57**	**8.43**	**8.70**	**8.97**	**9.42**	**10.47**	**10.65**

Source: U.S. Department of Energy, Energy Information Agency, Electric Sales and Revenue Reports

Table 9 Commercial Average Rates in the Midwest and U.S. (in cents)

	2000	2001	2002	2003	2004	2005	2006	2007
Illinois	7.53	7.40	8.30	7.22	7.54	8.05	8.04	9.01
Indiana	5.93	5.80	6.00	6.13	6.31	6.54	7.23	7.16
Iowa	6.57	6.70	6.60	6.24	6.75	6.95	7.45	7.19
Michigan	7.90	7.60	7.50	7.55	7.57	8.09	8.51	8.98
Minnesota	6.36	6.00	5.90	6.12	6.31	6.56	7.10	7.47
Missouri	5.83	5.90	5.90	5.78	5.80	5.88	6.27	6.45
Ohio	7.61	7.90	7.70	7.60	7.75	7.92	8.44	8.64
Wisconsin	6.03	6.40	6.50	6.97	7.24	7.61	8.40	8.64
Midwest Average	**6.82**	**6.76**	**6.84**	**6.66**	**6.91**	**7.20**	**7.68**	**7.94**
U.S. Average	**7.36**	**7.91**	**7.93**	**7.98**	**8.16**	**8.68**	**9.51**	**9.68**

Source: U.S. Department of Energy, Energy Information Agency, Electric Sales and Revenue Reports

Table 10 Industrial Average Rates in the Midwest and U.S. (in cents)

	2000	2001	2002	2003	2004	2005	2006	2007
Illinois	4.76	4.80	5.60	4.91	4.65	4.52	0.69	6.02
Indiana	3.81	4.00	4.00	3.92	4.13	4.40	4.99	4.98
Iowa	3.89	4.20	4.00	4.16	4.33	4.57	5.01	4.86
Michigan	5.10	5.20	4.90	4.96	4.92	5.58	6.05	6.52
Minnesota	4.57	4.60	4.20	4.36	4.63	5.06	5.27	5.78
Missouri	4.43	4.50	4.50	4.49	4.62	4.59	4.74	4.88
Ohio	4.47	4.70	4.70	4.79	4.89	5.03	5.60	5.78
Wisconsin	4.04	4.30	4.40	4.71	4.93	5.33	5.86	6.18
Midwest Average	**4.43**	**4.57**	**4.56**	**4.51**	**4.64**	**4.89**	**5.28**	**5.63**
U.S. Average	**4.57**	**5.07**	**4.84**	**5.13**	**5.27**	**5.57**	**6.19**	**6.38**

Source: U.S. Department of Energy, Energy Information Agency, Electric Sales and Revenue Reports

Energy Efficiency and Renewable Resources

ENERGY EFFICIENCY

Status of Energy Efficiency Efforts

Conservation and energy efficiency efforts encourage customers to reduce their use of electricity. Conservation saves energy or reduces demand by reducing the level of energy services (*e.g.* turning off lights, changing thermostat settings, taking shorter showers, etc.). Conservation generally involves behavioral changes. Energy efficiency is the application of technologies that use less energy while producing the same or a better level of energy services. These technologies are generally long-lasting and save energy whenever the equipment is in operation. Through the reduction in energy use, conservation and energy efficiency provide an important means for customers to control their electric bills. Conservation and energy efficiency have the additional benefit of reducing the need to build new power plants or transmission lines.

Prior to 2000, utilities had primary responsibility for energy efficiency services. 1999 Wisconsin Act 9 (Act 9) established a new mechanism, administered by the Department of Administration (DOA), for the funding and delivery of energy efficiency programs. Under Act 9, DOA contracted with third-party program administrators for the development and delivery of statewide energy efficiency (Focus on Energy (Focus)) programs. Energy efficiency programs through DOA-administered Focus programs were first made available to ratepayers in 2001 and remained in place until July 1, 2007.

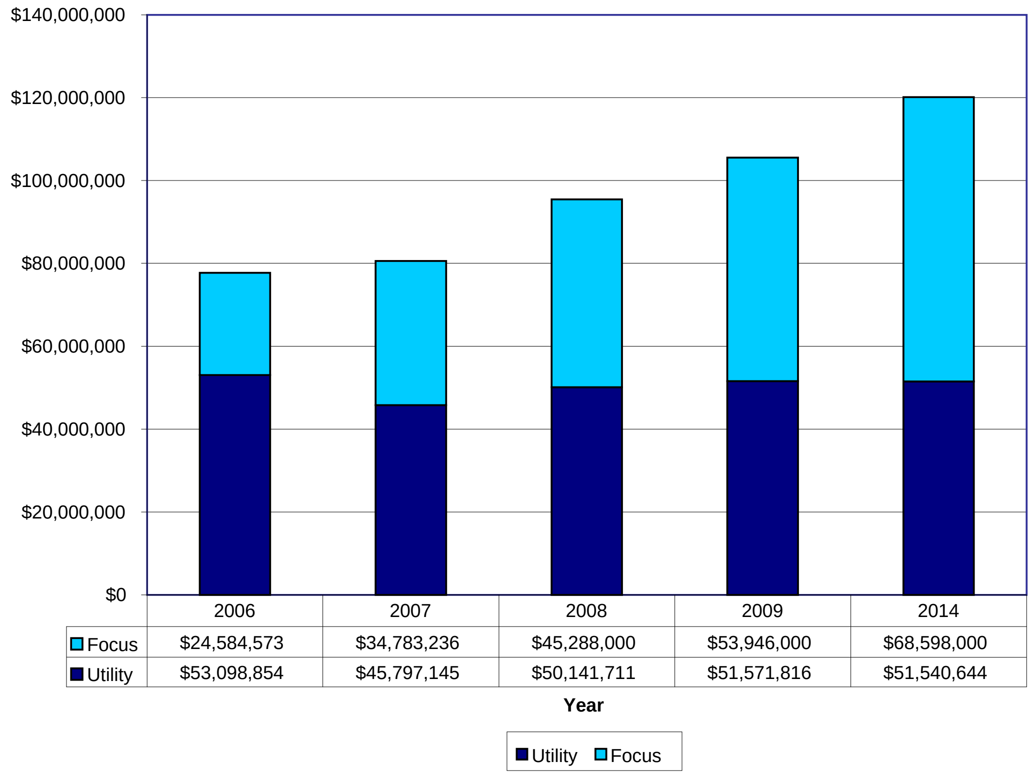
2005 Wisconsin Act 141 (Act 141) substantially revised the funding and structure of the statewide energy efficiency programs. Beginning July 1, 2007, the Focus programs are collectively funded by investor-owned utilities. In order to secure funding for the programs, the utilities directly contract with the program administrators. Funding of the Focus programs was increased to 1.2 percent of annual operating revenues. However, in years 2007, 2008, and 2009, a portion of this funding is retained by the utilities for their ordered programs.[7] Act 141 also provides the Commission oversight of the Focus programs.

The following figures provide the aggregate historical and projected electric conservation and energy efficiency expenditures, kW, and kWh savings of Wisconsin utilities, and the Focus programs for calendar years 2006-2009 and 2014. The charts include the aggregate expenditures and savings of the following utilities: MGE, NSPW, Superior Water, Light

[7] WEPCO and WPSC have energy efficiency programs that were required as conditions of orders in power plant approvals.

and Power, WEPCO, WP&L, and WPSC. Expenditures and savings for DPC and WPPI are also included.[8] Expenditures and savings for WEPCO's approved 2009-2010 voluntary utility programs are included, as are expenditures and savings for continuation of WP&L's Shared Savings program.[9] Utility customer service conservation expenditures are included. However, little or no savings are reflected for utility customer service conservation activities. This is because many of these services do not lend themselves to tracking and verifying the savings. Focus savings projections are based on the assumption of continued utility funding at a level of 1.2 percent of operating revenues. Focus expenditures and savings resulting from WPSC's commitment to contribute additional dollars to Focus in years 2009 through 2012 are not included in the charts. It is estimated that an additional $5.3 million may be available for energy efficiency in WPSC's service territory in 2009. Assuming savings achievement at the same cost per unit as achieved by Focus programs, these additional expenditures are estimated to achieve an additional 40,000 kWh and 7 MW in 2009.

Figure 9 Annual Energy Efficiency Expenditures (2006-2014)

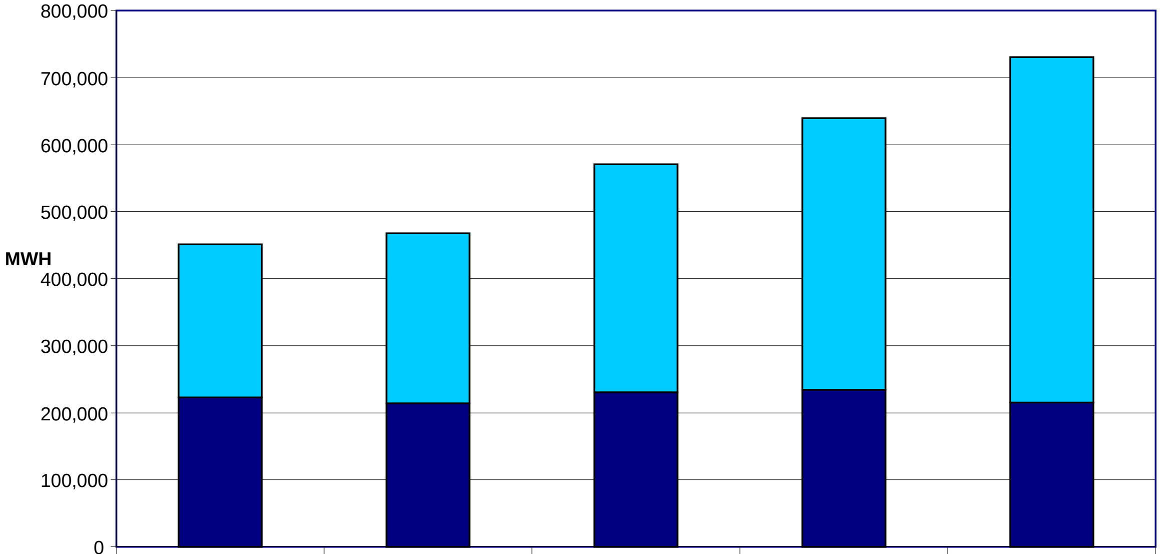


---

[8] Although electric cooperatives and municipal utilities that are not members of DPC or WPPI also provide conservation and energy efficiency services, their costs and savings are not included. Not all of these electric cooperatives and municipal utilities track achievement of energy and demand savings. Total spending of these utilities are less than 1.0 percent of the total expenditures of the utilities included in the figures. Because of the relative size of the electric cooperatives and municipal utilities, this omission does not greatly affect the aggregate totals.

[9] While expenditures and savings of utility-ordered and voluntary energy efficiency programs are included, not all of the utility programs were evaluated with the same level of rigor as the Focus programs.

Figure 10 Annual Energy Savings (2006-2014)

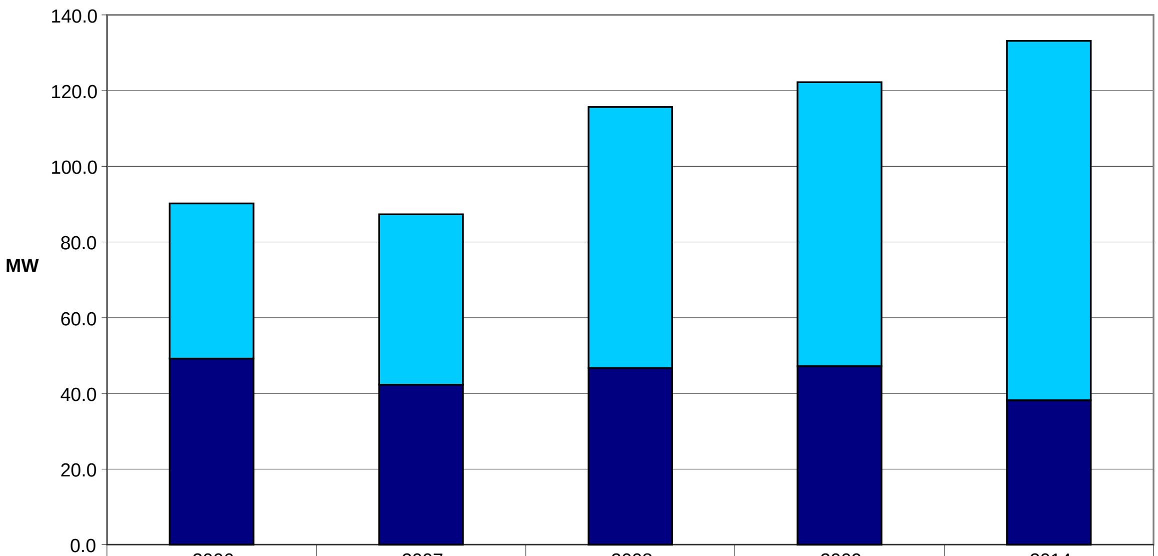


	2006	2007	2008	2009	2014
Focus	228,494	253,564	340,000	405,000	515,000
Utility	222,698	214,161	230,698	234,342	215,319

Year

Utility Focus

Figure 11 Demand Savings (2006-2014)



	2006	2007	2008	2009	2014
Focus	41.0	45.0	69.0	75.0	95.0
Utility	49.2	42.3	46.7	47.2	38.2

Year

Utility Focus

Analysis of Energy Efficiency Efforts

In the past there has been inadequate energy efficiency funding, resulting in a less than desirable level of energy efficiency savings. Funding for the Focus programs was determined by the legislature after considerable debate among various stakeholders. It was based on an analysis of energy efficiency potential that was limited in scope. The GWTF recommends increasing the capture of energy efficiency savings from the current annual reduction of 0.4 to 0.5 percent of electric usage to 2 percent by 2015. The GWTF suggests that a substantially higher funding level than the current 1.2 percent of operating revenues will be needed to capture maximum achievable potential.

The Commission has secured a contractor to conduct an energy efficiency potential study. The energy efficiency potential study will not only estimate maximum achievable potential, but also provide information regarding program designs and level of resources required to capture the identified potential. The results of this study will inform the Commission's first Act 141-required energy efficiency planning process, expected to occur in 2009. In this planning process the Commission will establish priorities, set overall energy efficiency savings targets, and set funding levels to reach these targets. The level of savings recommended by the GWTF is aggressive. This level of savings has not been achieved, on a statewide basis, by any current portfolio of programs. If the energy efficiency potential study indicates that it is possible to achieve the GWTF's recommended annual reduction of 2 percent of electric use, and sufficient funding is available, it will still be a challenge to identify the set of programs and policies that will be able to capture the savings. If funding above the current 1.2 percent of operating revenues is needed to meet the energy efficiency savings targets, the Commission can, with Joint Committee on Finance approval, require the utilities to spend a larger share of their operating revenues on statewide energy efficiency programs. If sufficient funding is not available to meet the Commission's established targets, the Commission will need to make some difficult choices regarding the priorities of the energy efficiency programs. For instance, the Commission may have to determine whether the programs should emphasize demand savings, which addresses reliability, or energy savings, which addresses greenhouse gas emissions.

RENEWABLE RESOURCES

Generation of Electricity from Renewable Resources

The generation of electricity from renewable sources is expected to increase steadily during the planning period. This growth will come from three areas—onsite customer generation, green pricing programs, and utility efforts to comply with the RPS. In 2007, about 2,746,725 MWh or 3.96 percent of all electrical energy sold in Wisconsin was generated from renewable resources.

Currently, Wis. Stat. § 196.378(2) requires all retail electric providers to provide a minimum portion of their total retail sales from renewable resources. A renewable resource baseline was established for each electric provider. By 2010, each electric provider is required to increase its renewable energy percentage so that it is at least 2 percent above its baseline renewable percentage. The overall effect of this RPS is to require10 percent of Wisconsin's total electric energy consumption in 2015 (and thereafter) to come from renewable resources. In 2007, all electric providers and aggregators were in compliance with the RPS.

The GWTF recommends the current RPS be amended to move the 10 percent renewable requirement forward from 2015 to 2013. The GWTF also recommends standards of 20 percent renewable energy by 2020 and 25 percent by 2025. An amended RPS would also include a minimum amount of the renewable energy come from Wisconsin-based renewable energy resources. This minimum amount would be 6 percent by 2020 and 10 percent by 2025.

In 2007, M-RETS was established and began issuing renewable energy certificates (REC). M-RETS is an electronic tracking and accounting system designed to support the growing market for RECs and green power in the Midwest. M-RETS is used to demonstrate compliance with Wisconsin's and other regional RPS. M-RETS also facilitates regional trading of RECs.

Customer Sited Renewable Generation

A portion, approximately 4.5 percent, of public benefit energy dollars go to the Focus Renewable Energy Program operated by Wisconsin Renewable Energy Network. For the calendar year 2007, the Focus Renewable Energy Program had a budget of about $3.3 million. The budget for calendar year 2008 increased to $5.5 million. Technologies covered by the Focus program include:

- Photovoltaic or solar electric;
- Small-scale wind;
- Biomass;
- Heat pumps;
- Solar water and space heating.

Incentives to encourage greater use of these renewable technologies by utility customers include cash-back awards, implementation grants, business and marketing grants, demonstration grants, feasibility grants, and technical assistance.

In calendar year 2007, energy savings produced by the Focus Renewable Energy Program were about 6 million kWh and 600,000 therms.

Environmental Issues

Wisconsin's SEA for 2008-2014 describes energy issues influenced by three forces: global warming; federalization of the electric system; and increasing energy costs. The timing and rate at which each of these forces will develop and affect Wisconsin's energy future are uncertain. Another major influence is the evolving implementation of the National Ambient Air Quality Standards. Many decisions made during this period will determine how well Wisconsin adapts to the forces of change. There is a potential for substantive change and the resultant environmental effects are uncertain.

The importance of energy efficiency, conservation, and load control to reducing Wisconsin's energy costs and environmental impacts is highlighted by the findings of the GWTF, as well as by analysis in the SEA. These energy management strategies also keep more money in the state and produce more Wisconsin jobs.

Rising costs will create hardships for people with low incomes. Provisions must be made to address this problem for public health, safety, and environmental reasons. The GWTF recommendations begin to address this issue.

Commenters' Critique of the Strategic Energy Assessment

The public comment portion of the SEA garnered several comments from the energy community. However, the most substantial sets of comments were from two parties that joined several entities together to comment. The first set of comments that will be addressed in this section came from the Joint Public Interveners (JPI), which was made up of Citizens' Utility Board, Clean Wisconsin, and RENEW Wisconsin. The second set of comments is from the Industrial Customer Group (ICG). This group compiles and presents comments from the Midwest Food Processors Association, Wisconsin Cast Metals Association, Wisconsin Industrial Energy Group, Wisconsin Manufacturers and Commerce, and the Wisconsin Paper Council. The comments from both the JPI and the ICG explore various areas of concern with the current SEA process. However, one of the common themes in the comments of both JPI and ICG are that they want more detail and further analysis within future versions of the SEA.

JPI specifically outlines in its request that the Commission consider expanding the SEA process to a "statewide, integrated planning process . . . to ensure environmental protection, an adequate supply of energy, and reasonable customer costs". JPI argues in its comments that "significant risks and uncertainties such as fuel price volatility, dramatically increased construction costs, environmental pollution including global warming, and a damaged economy all demand that regulators, utilities, and energy consumers work together in an effective and proactive manner, in order to plan for a reliable, sensible, and environmentally protective energy future for Wisconsin. " JPI indicates that the following specific elements must be present in future strategic planning efforts undertaken by the Commission, and that the current statutory provisions of the SEA are "inadequate to achieve any of these fundamental requirements to successfully meet the challenges of Wisconsin's energy future."

- Information and data that is independently verified and that is adequate to develop a specific action plan.
- The opportunity for parties with different perspectives to identify and evaluate the challenges that will shape energy policy in Wisconsin.
- The development of an action plan to move toward a desirable energy future for Wisconsin.[10]

[10] The bulleted list of considerations for future SEAs from both JPI and ICG are quoted directly from their filed comments with the Commission.

The concern over energy policy evolution in Wisconsin might also be how the comments of the ICG could be categorized, especially how energy policy choices on key issues facing the state in the coming years might affect Wisconsin utility rates, and specifically the industrial customers in Wisconsin. Along those lines, ICG indicates that it would like to see future SEAs be changed to focus on the following:

- The effect of CAIR, BART, and Wisconsin's mercury rule on electricity rates;
- Mitigating the cost of RPS compliance;
- Addressing the cost and revenue accounting-related aspects of utilities participating in the MISO Day II market;
- Assuring a utility fuel mix that makes economic and environmental sense for Wisconsin;
- Aggressively championing change within FERC to stringently mitigate market power, identify means to pass efficiency gains to end-use customers, and foster wholesale competition;
- Maximizing benefits from MISO as long as Wisconsin utilities are participating in it;
- Increasing efficiency and maximizing the use of existing supply side and demand side resources;
- Sending appropriate signals to help ensure utilities are adequately cost conscious and prudent when undertaking purchased power and other supply resource related decisions;
- Capturing the "biggest bang for the buck" in each and every initiative.

Global Warming Task Force Recommendations

On July 24, 2008, the GWTF overwhelmingly voted to finalize its report to the governor. Noting the significant impact from the consumption and generation of electricity in Wisconsin's total greenhouse gas emissions profile, the GWTF assembled recommendations both to promote conservation and energy efficiency, and to reduce the greenhouse gas emission profile of electric generation.

ENERGY SECTOR POLICIES

The utility sector was responsible for 34 percent of Wisconsin's greenhouse gas emissions in 2003. Direct fossil fuel use by the commercial and residential sectors was responsible for an additional 14 percent of Wisconsin's greenhouse gas emissions in 2003.

The GWTF recommends policies to aggressively promote much greater energy conservation and efficiency. It concluded that these policies provide the most effective and least costly early action strategies available for reducing greenhouse gas emissions. The policies are grouped into general categories, and call for:

- Enhancing Wisconsin's existing Focus on Energy program through adoption of challenging goals to reduce natural gas and electricity consumption, with substantially increased funding;
- Promoting conservation and efficiency through innovative utility rate designs and demand response programs, and removal of economic disincentives for utilities to aggressively promote and invest in conservation and efficiency measures;
- Adopting and maintaining state-of-the-art residential and commercial building codes and studying whether mandatory efficiency upgrades should be required for existing buildings at time of sale;
- State government taking a leadership role by reducing its own greenhouse gas emissions substantially;
- Creating energy efficiency standards for certain appliances and for lighting in rental properties;
- Promoting and incentivizing energy efficiency projects for schools and low income residences;
- Creating a new program similar to Focus on Energy to promote conservation and efficiency to customers who use propane, coal, or oil for heating;

- Promoting water conservation programs to reduce electricity use by water utilities.

The GWTF also recommends policies designed to promote cleaner electric generation technologies. These policies call for:

- Requiring utilities to develop greenhouse gas inventories and voluntary greenhouse gas reduction goals;
- Increasing substantially the amount of electricity produced from renewable resources, reaching 25 percent by 2025;
- Modifying Wisconsin's current moratorium on the construction of new nuclear power plants to allow this option to be considered in the future to meet Wisconsin's energy needs, after the GWTF's recommended policies for conservation, efficiency, and renewable energy are in place; and if certain other conditions are met, including a determination by the Commission that it is safe, economic, and in the public interest;
- Establishing statewide standards for siting wind power projects;
- Improving transmission infrastructure and interconnection processes to facilitate increased renewable energy projects and distributed generation;
- Studying the potential for geologic carbon sequestration and Great Lakes offshore wind power projects;
- Exploring new ways to mitigate the cost impacts of greenhouse gas policies on utility rates.

A technical analysis performed for the GWTF projects that these sector-based policies, collectively, may achieve the reductions necessary to meet the 2014 goal, but will only achieve approximately half of the reductions needed to meet the 2022 goal. The GWTF therefore recommends a cap and trade program to help achieve the other emission reductions needed to meet the 2022 reduction goal.

Acronyms

§	Section
Act 9	1999 Wisconsin Act 9
Act 141	2005 Wisconsin Act 141
AFUDC	Allowance Funds Used During Construction
ARC	Aggregators of Retail Customers
ATC	American Transmission Company LLC
Btu	British thermal units
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CC	Combined-cycle
Commission	Public Service Commission of Wisconsin
CO	Carbon monoxide
CO_2	Carbon dioxide
CPCN	Certificate of Public Convenience and Necessity
CT	Combustion turbine
D-T	Distribution to Transmission
DNR	Department of Natural Resources
DOA	Department of Administration
DOE	U.S. Department of Energy
DOT	Department of Transportation
DPC	Dairyland Power Cooperative
DSM	Demand-side management
ECW	Energy Center of Wisconsin
EGEAS	Electric Generation and Expansion Analysis System
EHV	Extra high voltage
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
EPAct 2005	Energy Policy Act of 2005
EPRI	Electric Power Research Institute
ERF	Electronic Regulatory Filing
FERC	Federal Energy Regulatory Commission
FGD	Flue gas desulfurization
Focus	Focus on Energy
FTR	Financial transmission rights
G-T	Generator to Transmission
GHG	Greenhouse gas
GW	Gigawatt
GWh	Gigawatt hour
GWTF	Governor's Task Force on Global Warming
HVAC	Heating/ventilating/air conditioning
ICG	Industrial Customer Groups
IGCC	Integrated gasification combined-cycle
IPP	Independent power producers
JCSP	Joint Coordinated System Plan
JPI	Joint Public Intervenors
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt hour
LMP	Locational marginal pricing
MACT	Maximum achievable control technology
MAIN	Mid-America Interconnected Network
MAPP	Mid-Continent Area Power Pool
MGE	Madison Gas and Electric Company

MISO or Midwest ISO	Midwest Independent Transmission System Operator, Inc.
mmBtu	Million British thermal units
MPU	Manitowoc Public Utility
M-RETS	Midwest Renewable Tracking System
MTEP	MISO Transmission Expansion Plan
MTEP08	MISO Transmission Expansion Plan 2008
MTEP09	MISO Transmission Expansion Plan 2009
MRO	Midwest Reliability Organization
MW	Megawatt
MWh	Megawatt hour
NAERO	North American Electric Reliability Organization
NCA	Narrowly constrained transmission area
NERC	North American Electric Reliability Council
NO_2	Nitric oxide
NO_X	Nitrogen oxides
NPV	Net present value
NRC	Nuclear Regulatory Commission
NSPW	Northern States Power-Wisconsin
O&M	Operations and maintenance
Ohio PUC	Ohio Public Utilities Commission
OMS	Organization of MISO States
PHEV	Plug-in hybrid electric vehicle
PJM	PJM Interconnection
PM	Particulate matter
PM_{10}	Particulate matter less than 10 microns in diameter
PM_{25}	Particulate matter less than 25 microns in diameter
PSC	Public Service Commission of Wisconsin
PTC	Production tax credit
PV	Photovoltaic
REC	Renewable energy certificate
ROW	Right-of-way
RTC	Regional Transmission Committee
RTO	Regional Transmission Organization
RPS	Renewable portfolio standard
SCPC	Super-critical pulverized coal
SCR	Selective catalytic reduction
SEA	Strategic Energy Assessment Report
SERC	Southeast Reliability Council
SO_2	Sulfur dioxide
SO_X	Sulfur oxides
SWL&P	Superior Water, Light and Power Company
T-T	Transmission to Transmission
TPSC	Transmission Planning Subcommittee
U.S.	United States
WEPCO	Wisconsin Electric Power Company
WIEG	Wisconsin Industrial Energy Group
Wis. Admin. Code	Wisconsin Administrative Code
Wis. Stat.	Wisconsin Statutes
WMC	Wisconsin Manufacturers and Commerce
WP&L	Wisconsin Power and Light Company
WPC	Wisconsin Paper Council
WPPI	Wisconsin Public Power, Inc.
WPSC	Wisconsin Public Service Corporation
WUMS	Wisconsin Upper Michigan System
Xcel	Xcel Energy, Inc.

GLOSSARY

Capacity	The maximum amount of power that a generating unit can create, usually measured in MW.
Capacity Factor	A calculation, expressed as a percentage such as 70 percent, representing the proportion of time in a year that a generating unit operates at its full electric generating output level.
Demand and Energy Charge	The combined fixed costs for the right to obtain capacity as well as the energy charges that are incurred to produce electricity.
Electric Demand	The amount of instantaneous draw of power from the electric system, usually measured in MW.
Electric Energy	The amount of electricity used over a period of time, measured in MWh.
Energy Charge	The variable costs, including fuel, that are incurred to produce electricity.
Flow Gate	A particular section of the transmission system where energy is monitored for excessive flow.
Focus on Energy Program	Energy efficiency and conservation program administered by the state Department of Administration and funded by the state's electric and gas utilities.
Independent Power Producer (IPP)	A non-utility business that constructs and operates power plants, who sells the electrical output into the marketplace.
Marginal Energy Cost (MEC)	The cost of electric energy for the last unit produced, usually measured in $ per MWh. The MEC is usually comprised of fuel cost, and variable operation and maintenance costs.
Native Load	The amount of electric demand, representing the customers in its service territory that a utility is obligated to serve.
Non-Coincident Peak Demands	Peak Demand of each utility added together to derive a statewide total. Such demand is considered non-coincident because each utility may have had peak demand occur at a different hour or day.
Peak Electric Demand	The amount of instantaneous draw of power from the electric system at the moment of highest use, usually on a hot humid summer day.
Power Purchase Agreement (PPA)	A contract in which an electric generating company sells capacity and energy to a utility.
Therm	A unit used to measure the quantity of heat that equals 100,000 Btu.
Transfer Capability	The amount of electrical output measured in MW that can move over a set of high voltage transmission lines from one area to another.
Sales and Purchases on a Unit Basis	The exchange of electric power and energy from a dedicated generation plant.
Sales and Purchases on a System Basis	The exchange of electric power and energy from a provider's fleet of generation plants.
Simultaneous Transfer Capability	The amount of electrical output measured in MW that can move over all sets of high voltage transmission lines at the same time from one area to another.
With or Without Reserves	A contract specification for an exchange of power and energy in which the seller does or does not provide the additional capacity required so that the sale has the same high level of dispatch priority as native load.

Appendix A

Table A-1 New Utility-Owned or Leased Generation Capacity, 2008-2014

Year	Type of Load Served	Capacity (MW)	Name	New or Existing Site	Owner/ Leaser	Fuel	Location (County: Locality)	PSC Status & Docket #
2008	Base Load	515	Weston Unit 4	Existing site	WPSC, DPC	SCPC coal	Marathon: Villages of Rothschild & Kronenwetter	Approved 6690-CE-187
2008	Base/Intermediate - Combined Cycle	575	Port Washington Unit 1	Existing site	We Power	Natural gas	Ozaukee: City of Port Washington	Approved 5-CE-117
2008	Non-dispatchable[1]	145	Blue Sky/ Green Field (88 turbines)	New site	WEPCO	Wind	Fond du Lac: Towns of Calumet & Marshfield	Approved 6630-CE-294
2008	Non-dispatchable[1]	129	Forward (66 turbines)	New site	Invenergy	Wind	Dodge & Fond du Lac: Towns of Byron, Oakfield, Lomira, & Leroy	Approved 9300-CE-100
2008	Non-dispatchable[1]	67.6	Cedar Ridge (41 turbines)	New site	WP&L	Wind	Fond du Lac: Towns of Eden & Empire	Approved 6680-CE-171
2008	Non-dispatchable[1]	30	Top of Iowa 3	Existing site	MGE	Wind	Iowa	Approved 3270-CE-126
2009	Base load[2]	615	Elm Road Unit 1	Existing site	WEPCO	SCPC coal	Milwaukee: City of Oak Creek	Approved 5-CE-130
2009	Peak load	55	Marshfield M-1	New site	Marshfield Utilities	Natural gas	Wood County: City of Marshfield	Approved 3420-CE-111
2009	Peak load	12	Concord Units 3 & 4	Upgrade to existing unit(s)	WEPCO	Natural gas	Jefferson: Watertown	Approve 6630-CE-300
2010	Base load[2]	615	Elm Road Unit 2	Existing site	WEPCO	SCPC coal	Milwaukee: City of Oak Creek	Approve 5-CE-130
2010	Non-dispatchable[1]	100	Crane Creek Wind Farm	New site	WPSC	Wind	Howard County: Iowa	Approved 6690-CE-194
2010	Non-dispatchable[1]	200	Bent Tree Wind Farm	New site	WP&L	Wind	Freeborn County: Minnesota	Under Review 6680-CE-173
2010	Non-dispatchable	234	Glacier Hills	New site	WEPCO	Wind	Columbia County	6630-CE-302
2011	Base load[4]	90	Point Beach Units 1 & 2	Upgrade to existing unit(s)	WEPCO	Nuclear	Kewaunee: Town of Two Creeks	NA
2011	Peak load	100	Combustion Turbine (CT) #1	To be determined	Dairyland Power	Natural gas	To be determined	No application filed
2014	Peak load	167	New CT #1	To be determined	WPSC	Natural gas	To be determined	No application filed
2014	Peak load	167	New CT #2	To be determined	WPSC	Natural gas	To be determined	No application filed
2014	Non-dispatchable[1]	100	Not named	Probably new	WPSC	Wind	Probably not in Wisconsin[3]	No application filed
2016	Non-dispatchable[1]	100	Not named	Probably new	WPSC	Wind	Probably not in Wisconsin[3]	No application filed

1 Nameplate MW shown. Wind operates when the wind blows: MW counted as firm are 20% per year ave. or less (more wind in winter than summer).
2 Elm Road Generating Station Units 1 and 2 will each be rated at 615 MW. Wisconsin Electric will lease 515 MW from each unit.
3 The higher wind speed in MN and IA provides less-costly capacity (MW) than turbines located in WI.
4 Power sold to WEPCO by Florida Power & Light (FPL) under a Purchased Power Adjustment (PPA)

Table A-2 New Transmission Lines[1] (on which construction is expected to start by December 31, 2014)

PSC Status & Docket #	New Line or Rebuild/Upgrade[2]	Endpoints (Substations)	County	Voltage (kV)	Est. Cost (Millions)	Expected Construction	Expected In-Service	Substation Changes
American Transmission Company LLC (ATC)								
137-CE-140 No application filed	Use structures on existing line	Canal - Dunn Road	**Door**	138	9	Dec-11	Jun-12	Yes
137-CE-155 Application filed	Rebuild 69 kV line to 138 kV	Brodhead - South Monroe	**Green, Rock**	69 (built for 138)	12	Jan-11	May-12	No
137-CE-147 Application filed	New	Rockdale - West Middleton	**Dane**	345	221	Jun-09	Jun-13	Yes
No application filed	Replace existing 69 kV line w/double-circuit 161/69 kV. About 1.3 miles of 69 kV reroute (new ROW)	Monroe Co. - Council Creek	**Monroe**	161	22	Jun-11	Dec-12	Yes
137-CE-127 No application filed	New 115 kV line to new substation	Clear Lake - Arnett Road[3] (Woodmin)	**Oneida, Vilas**	115	12	Jul-11	Jun-12	New substation, changes at Clear Lake Substation
Dairyland Power Cooperative (DPC) with Northern States Power - WI and Northern States Power - MN[3]								
5-CE-136 Filed w/MN PUC - WI PSC filing later	New 345 kV line; possibly replace existing 69 kV line from Alma Power Plant to N. LaCrosse	Hampton Corner (North Rochester-Twin Cities area) - La Crosse area	**Buffalo, Trempealeu, LaCrosse**	345	360	Jun-10	Dec-15	Yes (at North La Crosse Substation)
Northern States Power of Wisconsin (NSPW)[4]								
4220-CE-168 Application filed	New double-circuit and single-circuit 161 kV to replace existing 69 kV	Eau Claire/Chippewa Falls area (Eau Claire - Hallie)	**Eau Claire, Chippewa**	161	34	Winter 08 or Spring 09	Dec-11	New Gravel Island Substation at intersection of existing lines
4220-CE-170 No application filed	New substation; no transmission line	New (Three Lakes) substation on Pine Lake - Willow River line	**St. Croix**	115	16	To be determined	To be determined	New 115/69 kV Substation at crossing of Willow River-Pine Lake 115 kV line and Kinnickkinnick-Roberts 69 kV line
No application filed	New substation; less than 1 mile of new 161 kV line	New substation to transfer Rush River substation load to Pine Lake-Crystal Cave 161 kV line	**St. Croix**	161	3	To be determined	To be determined	New 161 kV Substation and upgrade of Rush Substation to 161 kV

1 Does not include lines approved by the Commission

2 Rebuilds and upgrades, as well as new lines, may require new right-of-way

3 See Table A-03

4 Northern States Power - Minnesota has a Resource Plan that may possibly affect WI transmission (wind & combustion turbine facilities not yet sited).

Table A-3 More Detailed Information for Two New Transmission Lines Proposed in Table A-2*

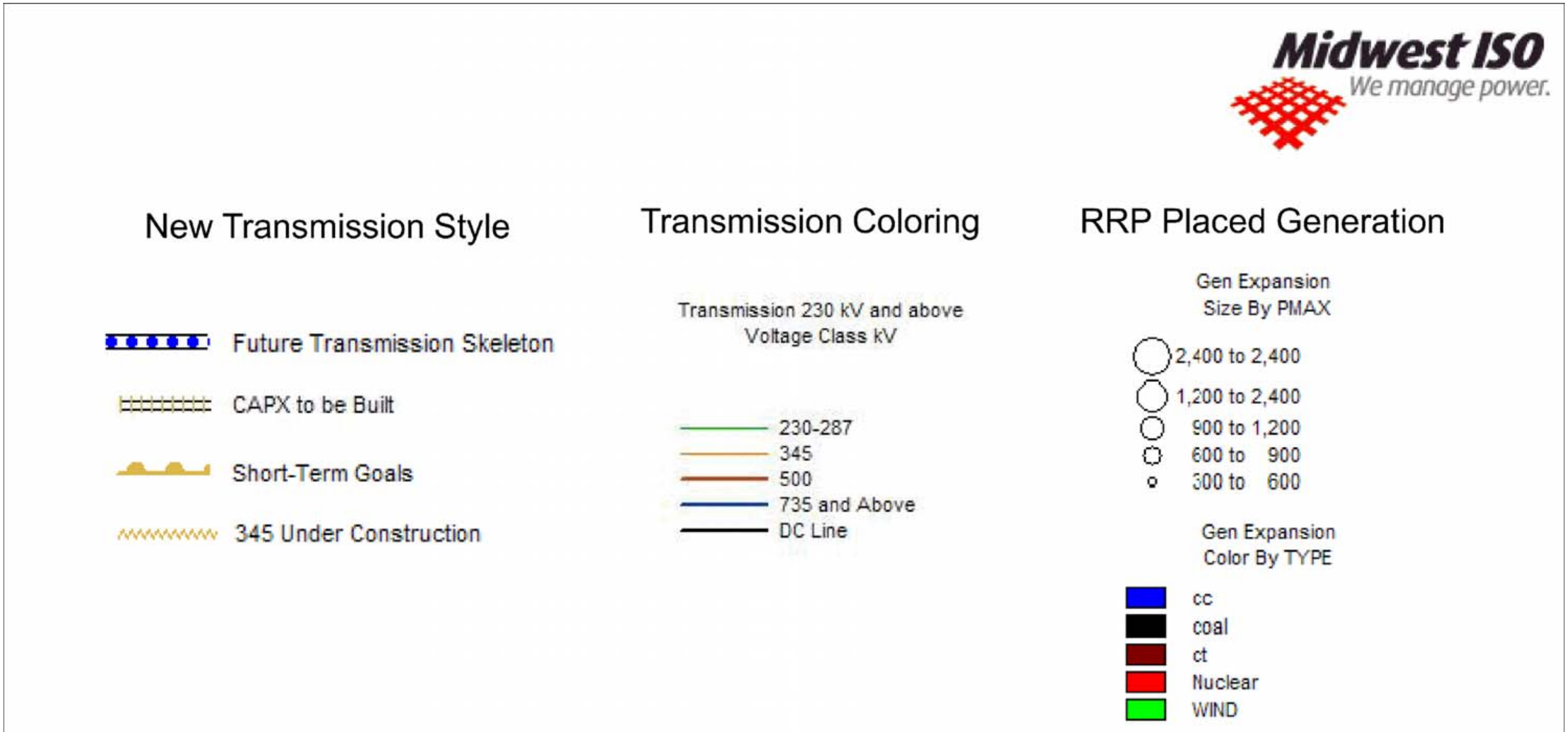
Project	Hampton Corners (MN) - LaCrosse Area 345 kV
Voltage (kV)	345 kV
Length (miles)	120-150 miles (about 40 miles in WI)
Screening Area	5,500 square miles - overall study area is 100 miles by 55 miles, covering both Minnesota and Wisconsin
Corridor-sharing Opportunities	Wisconsin only - existing DPC and NSPW 161 and 69 kV lines, Highway 35
Public Lands	Upper Mississippi NationalFish and Wildlife Refuge, Trempealeau National Wildlife Refuge, Whitman Dam Wildlife Area, Perrot State Park, Merrick State Park, Van Loon Wildlife Area, Great River State Trail
Sensitive Resources	Blufflands, Mississippi River (numerous resources associated with this, including flyway issues and wetland issues), prairie remnants, wetland complexes, Waumandee, Black, Trempealeau and La Crosse Rivers,
Cultural Resources	There are numerous cultural resources within the study area
Miscellaneous	A Certificate of Need was filed with the Minnesota Public Utilities Commission on August 16, 2007. The docket number is ET02, E-002/CN-06-1115. Additional environmental information is available in that docket.
Project	**Clear Lake - Arnett Road (Woodmin) 115 kV**
Voltage (kV)	115 kV (built to 138 kV standards)
Length (miles)	7 miles
Screening Area	9.2 square miles - overall study area is approximately 6 miles by 4.5 miles in Oneida and Vilas Counties
Corridor-sharing Opportunities	Existing distribution State Highway 70, State Highway 47, former rail corridor, County Highway J and local roads
Public Lands	Northern Highland - American Legion State Forest (including Clear Lake Campground, Raven Trail, DNR Fish Hatchery), Woodruff - Arbor Vitae School Forest, skateboard park
Sensitive Resources	Minocqua Thoroughfare, Tomahawk River, Johnson Lake, osprey platform, and wetland areas are DNR areas of special natural resources interest. Most of the small lakes (less than 50 acres) within the study area are designated by DNR as priority navigable waterways.
Cultural Resources	No cultural resources identified at this time; study in progress
Miscellaneous	No miscellaneous issues identified at this time

* Excludes projects already filed with the PSC and those proposed to center on existing right-of-way.

Table A-4 Utilities' Proposed Emission Control Equipment Installation Estimates Used for EGEAS Modeling

UNIT	APPLICATION FILED WITH COMMISSION	YEAR ORIGINAL UNIT RETIRED	YEAR UNIT WITH CONTROLS INSTALLED
Columbia 1	No	2013	2014
Columbia 2	No	2011	2012
Edgewater 4	No	2010	2011
Edgewater 5	No	2012	2013
Nelson Dewey 1	Yes	2014	2015
Nelson Dewey 2	Yes	2013	2014
Oak Creek 5	Yes	2012	2013
Oak Creek 6	Yes	2012	2013
Oak Creek 7	Yes	2012	2013
Oak Creek 8	Yes	2013	2014
Pulliam 7	No	2013	2014
Pulliam 8	No	2013	2014
Valley 1	Yes	2013	2014
Valley 2	Yes	2014	2015
Weston 2	No	2014	2015
Weston 3	No	2013	2014

Figure A-1 Universal Legend for Transmission



Detailed analysis of those Projects already in Appendix B will be performed as part of MTEP08. However, most of the facilities identified in Step 3 of the MTEP08 process should generally be considered as conceptual; and, will be placed Appendix C for further analysis. Appendix C projects are not in the models but are available for MTEP analysis.

Figure A-2 MISO Centric Transmission Scenario

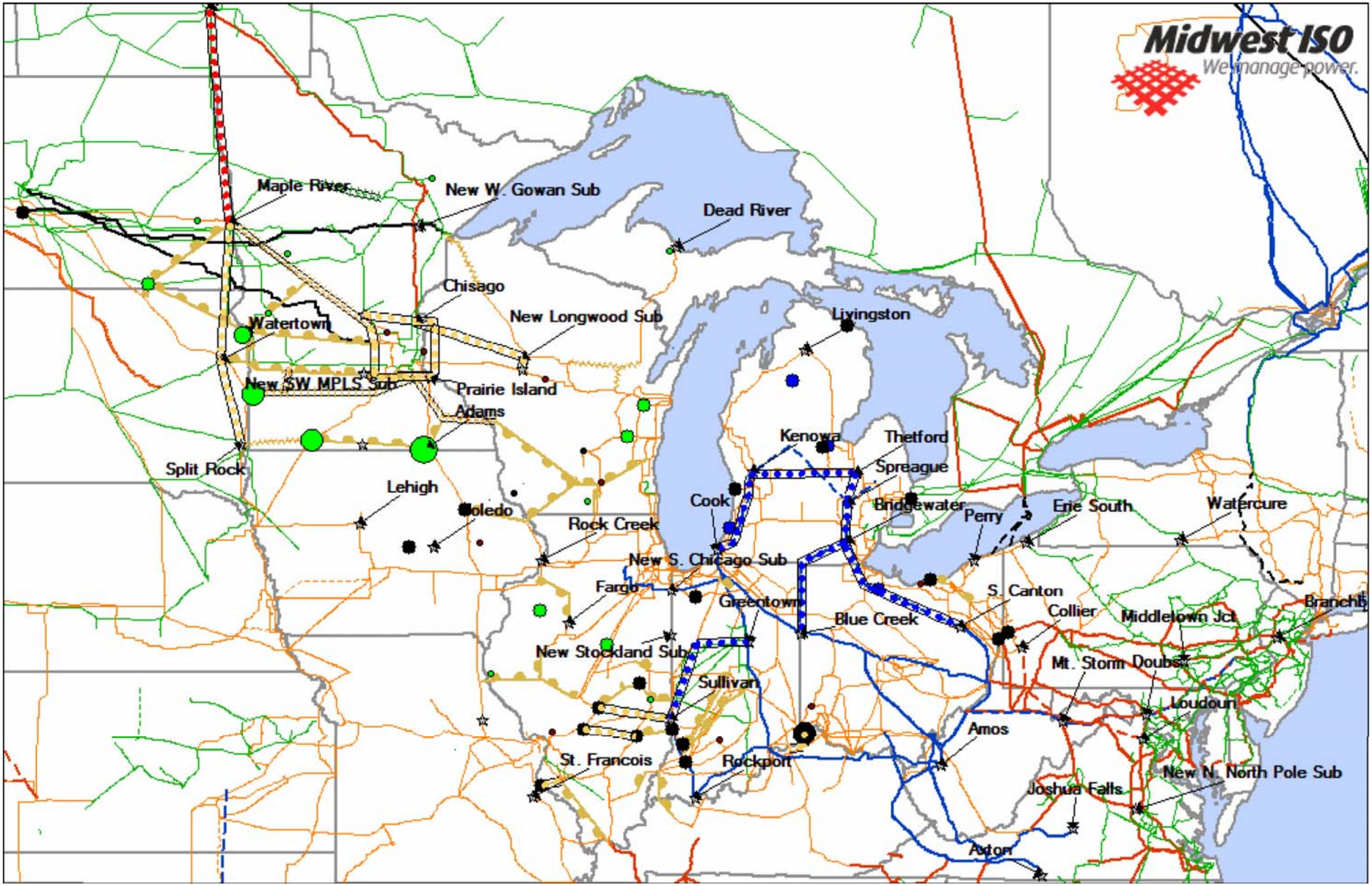
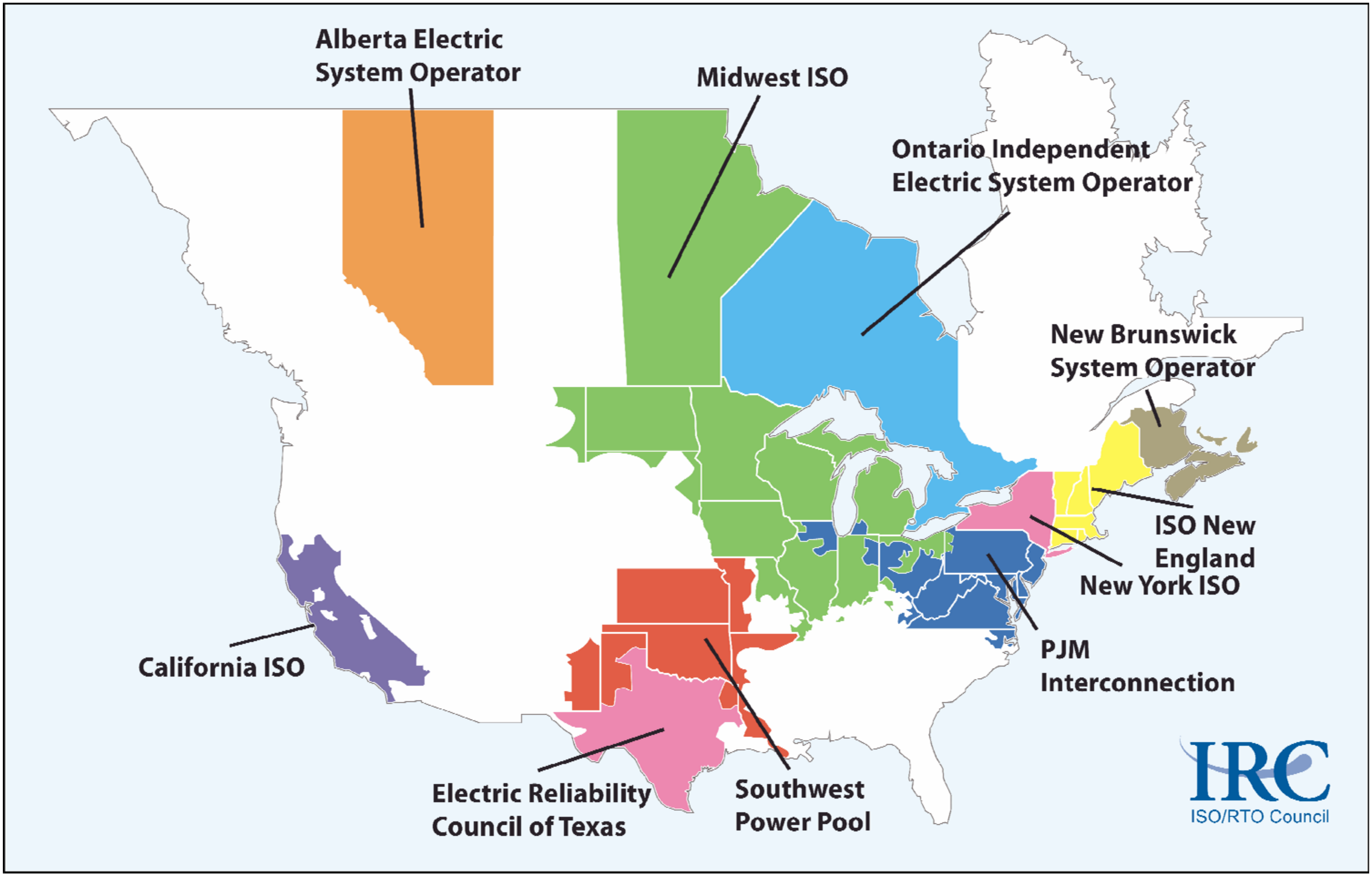


Figure A-3 Map of Regional Transmission Organizations



Appendix B

The Nine Planning Principles of FERC Order 890

1. **Coordination**—The transmission providers must meet with all of their transmission customers and interconnected neighbors to develop local and/or regional transmission plans on a non-discriminatory basis. Details such as meeting structures, responsibilities of parties, and how decisions are made are required.
2. **Openness**—The transmission planning meetings must be open to all affected parties including but not limited to all transmission customers and interconnection customers, state authorities, and other stakeholders. A process to manage confidential data such as Critical Energy Infrastructure Information is to be described
3. **Transparency**—The transmission provider must produce in writing and make available the basic methodology, criteria, and processes for developing transmission plans. This includes the planning cycle and milestones. The criteria used in the methodology must be described such as load flow, stability, short circuit, voltage collapse, production costs, etc. The assumptions regarding the transmission, generation, and demand response resources for model building are documented and a process for updates identified.
4. **Information Exchange**—The network customers are required to submit information on their projected loads and resources on a comparable basis and point-to-point customers on their service requirements. For the planning process the customers submit generation planned additions, upgrades, or retirement along with any environmental restrictions. Customers also submit existing and planned demand response resources and their impact on demand.
5. **Comparability**—The transmission plan must meet the specific service requirement of their transmission customers and treats similarly-situated customers the same in the planning process. The important change is to consider demand response as a resource, where appropriate, in planning.
6. **Dispute Resolution**—The transmission providers must identify a process to manage disputes that arise in the planning process. The steps of resolution are described in the negotiation, mediation, and arbitration, and only go to complaint to the Commission during the negotiation or mediation step.
7. **Regional Participation**—In addition to preparing a system plan for its own control area on an open and non-discriminatory basis, each transmission provider is required to coordinate with interconnected systems. This principle includes description of the interaction of local planning and regional planning activities. The use of sub-regional groups has been identified, and the description of inter-regional planning activities that could relieve congestion across multiple regions. The inter-regional coordination should strive for consistency in planning data and assumptions. A key and very important point is a description of the process for determining whether the transmission plans developed on a local, sub-regional, and inter-regional basis are simultaneously feasible.
8. **Economic Planning Studies**—The transmission providers must account for economic as well as reliability considerations in the transmission planning process. The process for requesting economic studies and procedures must be published along with the study information. The mechanism for recovering the costs incurred to perform the economic planning studies described and reflected in their OATT.
9. **Cost Allocation**—The cost allocation of new facilities that do not fit existing rate structures must be addressed. This includes the methodology for allocating costs associated with reliability and economic upgrades. Attachment K must describe the roles and responsibilities of the transmission provider and stakeholders during the cost allocation process.